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PROJECT FINANCE

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Carbon Border Adjustments

by Andrew Hedges, in London

As the United States debates whether to impose a carbon border adjustment, it might be instructive to understand how Europe is proposing to do it.

Detailed proposals on a carbon border adjustment mechanism — referred to in Europe as CBAM — were released by the European Commission in mid-July as part of a wider package of reforms designed to implement a target of a 55% reduction in carbon emissions by 2030.

The CBAM proposals are just the start of a legislative process that will take months to complete. The final design may well be different as the EU navigates that process.

Why CBAM Now?

CBAM is the next stage in the EU tackling the issue of carbon leakage.

Carbon leakage refers to a possible increase in global emissions linked to the relocation of industry from countries with stringent climate policies to countries with no or limited climate policies in place.

This has been a long-standing issue in the EU (particularly for industry groups) as the EU has had in place an emissions trading system (called the EU ETS) since 2004. Industrial sectors that compete in international markets have been consistently concerned with the impact of the EU ETS.

To date, the EU approach to managing the risk of carbon leakage has been by allocating free emission allowances to sectors that face stiff competition from */ continued page 2*

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UTILITIES are financing solar projects in the tax equity market in a manner that produces enhanced benefits.

The Internal Revenue Service described two such transactions in a pair of private letter rulings that the agency made public in late July and early August.

In one of the cases, a utility signed a build-transfer agreement with a solar company to buy a solar project near the end of construction. Rather than buy the project directly, it assigned the build-transfer agreement to a tax equity partnership. The partnership will buy the project using capital contributed by the tax equity investor and the utility.

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companies in other countries that do not require allowances to cover emissions and by allowing EU member states to compensate exposed sectors for increased energy costs arising from the EU ETS. The exposed sectors are defined by the EU, with the current list specified through 2030.

These carbon leakage tools have been subject to regular adjustments, such as tying the level of free allowances allocation to the emissions performance of the best installations (known as benchmarks).

In late 2020, the EU agreed to increase the 2030 reduction target to 55%. This triggered a process to re-assess existing climate policies with a view to amending those to achieve the increased target. For example, the cap on emissions under the EU ETS is to be tightened and new sectors will be covered. Carbon leakage tools have also undergone a review.

Carbon border adjustments are tariffs on products imported from countries with less stringent carbon controls.

EU policy makers were driven to a CBAM by two key factors.

First, as the cap on emissions under the EU ETS decreases, free allocation of allowances is increasingly unworkable as it will start to shift a disproportionate level of cost onto sectors that are not on the list of exposed sectors.

Second, the EU wants to push trading partners to make stronger efforts to reduce emissions. A policy paper the European Commission issued in 2019 on the European green deal said, "should differences in levels of ambition worldwide persist, as the EU increases its climate ambition, the Commission will propose a carbon border adjustment mechanism, for selected sectors, to reduce the risk of carbon leakage."

By imposing a carbon cost on certain imports, a CBAM can enable the progressive winding back of free allocation to exposed EU sectors.

For EU policy makers, ending or reducing free allocation would also significantly increase government revenues through the auctioning of those allowances. Supporting analysis released with the proposal estimates additional revenues in 2030 from reduced free allocation and CBAM to be between €13 and €15 billion.

Core CBAM Elements

At a high level, the proposed CBAM creates an obligation on importers of certain products to purchase CBAM certificates matching the embedded emissions associated with that product at a price matching then-current EU ETS allowance prices, unless certain exemptions apply.

It will be introduced on a transitional basis starting in 2023, with full implementation for covered products from the start of 2026.

The initial products to be covered are cement, electricity, iron and steel, fertilizers and aluminium.

The proposed regulation provides detailed breakdowns of sub-product types within each of these. For example, for iron and steel, ferrous scrap is not covered, but a range of other sub-products are, including sheet piling of iron or steel, railway track, tubes and pipes, vats and structures such as bridges, gates, towers, roofing and window frames.

The European Commission is authorized to monitor and adjust the scope of products covered to address circumvention risks, such as changes in the pattern of trade due to replacing CBAM-covered goods with slightly modified products that are not covered.

When a product (or a processed product from it) is imported into the EU, the importer will have to apply for authorization under the CBAM regulation. The process for authorisation will involve assessment of the financial and operational capacity of the applicant. If the applicant has been in existence for less than two years, then bank guarantees will be required for the maximum likely annual liability of the applicant.

This could inject some sand in the gears of cross-border trade in theory, but it is not expected to be any more burdensome than current processes for clearing imported goods that are subject to duties.

Each authorized importer will have to submit, by May 31, CBAM certificates matching the embedded emissions determined for imports of the covered products for the previous calendar year. Failure to do so will trigger financial penalties, including a fine of €100 per certificate not submitted plus a continuing obligation to submit the shortfall in certificates.

Importers will buy CBAM certificates that will be issued into an electronic registry account of the authorized importer.

The price for CBAM certificates will be set weekly at the average price of auctioned EU ETS emission allowances for that week.

If an authorized importer holds excess CBAM certificates after the compliance date of May 31, then it can return them for a refund of the original price paid. All excess CBAM certificates for a year will be cancelled on the June 30 after the compliance deadline. The draft regulation does not appear to allow the trading of CBAM certificates, but this is not entirely clear. Stakeholders are expected to suggest enabling trading of CBAM certificates to support risk mitigation tools such as hedging products.

The general approach is to use actual emissions calculations, but the use of default values is allowed where actual emissions are not available.

Although the draft regulation specifies a formula for the determination of the embedded emissions of a covered product, the regulation also envisages the European Commission developing detailed rules. For example, the expectation is that the default values will be "adapted to particular areas, regions or countries to take into account specific objective factors such as geography, natural resources, market conditions, prevailing energy sources, or industrial processes."

Importantly, installations outside the EU will be able to register under the CBAM in order to generate product-specific embedded emissions information for importers.

When an importer submits its annual calculation of embedded emissions of imported products, this will need to be accompanied by a verification statement from an */ continued page 4*

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Around the same time, the utility will sign a long-term power contract to buy electricity from the project for monthly payments that are either a fixed amount per megawatt hour of electricity or a fixed monthly charge. The payments are a negotiated amount rather than the retail rates that the utility charges its ratepayers for electricity. The utility will resell the electricity to its ratepayers at the retail rates.

Tax equity accounts for roughly 35% of the capital stack in a typical solar tax equity partnership, plus or minus 5%. The rest is capital put in by the sponsor — in this case, the utility.

The structure produces two benefits for the utility.

First, the utility puts its capital contribution for roughly 65% of the project cost into rate base. Thus, this factors into the calculation of the retail rates it can charge ratepayers.

Second, it passes through to ratepayers as a purchased-power expense the amount it pays the partnership for the electricity.

Utilities have been asking the IRS to confirm that projects owned through such structures are not "public utility property." Investment tax credits and accelerated depreciation are harder to claim on such property. Neither tax benefit can be claimed on such property if the owner is forced to pass through the value of the tax benefits to ratepayers more quickly than under a "normalization" method of accounting.

The IRS has confirmed in multiple rulings in the past two years that projects owned through tax equity partnerships are not public utility property. (For more details, see "Utility Tax Equity Structures" in the December 2019 *NewsWire*, "Solar Projects and 'Public Utility Property'" in the October 2020 *NewsWire*" and "Public Utility Property: More IRS Rulings" in the December 2020 *NewsWire*.)

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accredited verifier. The challenges of this requirement are recognized by the draft regulation by noting that the European Commission may develop rules relating to the waiver of this requirement.

There are two ways an importer will be able to reduce its liability under the CBAM.

The first is where it can be demonstrated that declared embedded emissions were subject to a carbon price in the country of origin. A "carbon price" is defined as "the monetary amount paid in a third country in the form of a tax or emission allowances under a greenhouse gas emissions trading system, calculated on greenhouse gases covered by such a measure and released during the production of goods."

The second way is where there continues to be free allocation of EU ETS allowances for the same product in the EU. In that case, the CBAM obligation for the importer is reduced to take account of this. The notion must be that importers should not be put at a disadvantage in instances where there is no requirement for the same product made in the EU to reduce emissions.

Full implementation of the package is not planned until January 2026. In the initial transitional phase from January 2023 to December 2025, the obligation will be limited merely to reporting of embedded emissions.

Implementation Challenges

CBAM remains a proposal. Ahead is the usual fraught EU legislative process involving the European Commission, EU member state governments, the EU parliament and stakeholders such as industry and environmental groups.

In addition, EU trading partners will have strong views on these proposals. Trading partners that will be particularly affected are those with the largest exports of relevant goods to the EU. For example, the top exporters for covered products are (using 2019 data): Russia, Ukraine, Turkey and China for iron and steel, Russia, the United Arab Emirates and China for aluminum, Russia, Egypt and Algeria for fertilizers, and Turkey, Ukraine and Belarus for cement.

If CBAM moves ahead, it is not hard to envisage challenges being made under World Trade Organization rules.

WTO disputes regarding trade issues arising from environmental measures date back decades, with likely focus being on issues such as whether the final CBAM breaches binding tariff arrangements the EU has agreed to on products, discriminates between imported products and EU products, amounts to a prohibition on certain types of imports or amounts to discrimination among countries. It is worth noting that the European Commission analyzed these issues in designing the proposed CBAM. Further, a WTO dispute does not prevent the CBAM being implemented while the dispute is ongoing.

On balance, we do see the CBAM moving ahead broadly as planned. However, it is important to recall the design element that that the CBAM obligation will not apply to the extent free allocation continues within the EU for a relevant product. As such, while the CBAM system may be implemented from 2026, the extent to which it starts to bite will be linked to the phase out of free allocations. That is likely to move at a slower pace than EU policy makers hope.

Much of the implementation period from 2026 to 2030 is likely to be taken up with the painful process of trying to translate the CBAM into workable rules for importers and exporters. As with the introduction of the EU ETS, this will also involve discussions between contract parties regarding allocation of liabilities for the additional costs arising from the CBAM. ◎

Europe will impose them starting in 2023 on a provisional basis.

Net Zero as Moonshot

by Michael Edesess, with M1K LLC in Hong Kong

President Biden's stated greenhouse gas reduction goal for the United States is "to create a carbon pollution-free power sector by 2035 and net zero emissions economy by no later than 2050."

Are these goals realistic, and what are the chances of meeting them?

It helps to lay out what sort of developments net zero by 2050 implies.

Ambitions and Aspirations

Announcing a goal of zero net carbon emissions by 2050 is like announcing a moonshot and hoping that the ambition will carry us to the goal. But like President John F. Kennedy before announcing the moonshot goal in 1961, we need to have some preliminary calculations, informed by current knowledge of science and technology, to get at least a sense of what will be needed.

When Kennedy proposed to Congress, on May 25, 1961, the goal of landing a man on the moon before the end of the decade, it was not known exactly how this would be done, or if it was even possible. It wasn't even popular with the voting public.

Nevertheless, the act of setting the goal, and assigning the task of achieving it to the new agency NASA — the National Aeronautics and Space Administration — set in motion an unprecedented series of innovations and technological developments that ultimately succeeded in achieving the goal. It also spawned an impressive array of important spinoffs in the process, helping to spark the breakthrough technologies of the late 20th and early 21st centuries.

It didn't even cost the US taxpayer very much. The cost of the moonshot program, Project Apollo, from 1960 to 1973 was only $28 billion, or about $280 billion in today's dollars.

Those who now advocate that the United States should target net zero emissions of greenhouse gases by the year 2050 are advocating a new moonshot, with hopes for similar successes.

We do not know exactly how we can get there or if it is even possible. But it is believed that setting the goal will, like the goal of the moonshot, set in motion innovations and technological developments that will ultimately enable us to achieve that goal and create many positive spinoffs besides.

Hope, optimism, and ambition, however, are not by themselves enough to achieve a goal. President Kennedy and his vice president, Lyndon Johnson, consulted top scientists to assess

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IRS regulations treat a power plant as public utility property only if the rates at which electricity is sold are established or approved by a regulator on a rate-of-return or cost-of-service basis.

The IRS has focused in rulings on the intermediate sale of the electricity by the partnership to the utility and ignored the resale at regulated retail rates.

The most recent ruling is Private Letter Ruling 202131004.

Solar tax equity partnerships normally throw off net tax losses for the first three years due to accelerated depreciation.

A partnership cannot claim a net loss on sales of goods — including electricity — to a related party. A partner is considered related if it owns more than a 50% profits or capital interest in the partnership.

It is not evident from the ruling how the parties dealt with this "section 707(b) issue."

Most sponsors (in this case, the utility) are careful to structure the offtake contract so that it is not a power contract. They make it a financial swap to put a floor under the electricity price to support the tax equity deal or a commission arrangement where the sponsor affiliate is paid a fee to sell the electricity for the partnership into an organized market, with the partnership keeping all of the revenue after paying a fee.

The IRS has explicitly declined to give any comfort on the issue in recent rulings.

If the utility pays a fixed monthly charge to the partnership instead of a per-MWh charge for the electricity, it might turn the power contract into a lease in substance of the power plant to the utility. A power plant leased to a utility is considered public utility property or not based on whether the lessee sells the electricity at regulated rates. That might be a problem in this case.

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whether it was possible, how difficult it would be and how it could be achieved.

Hierarchy of Options

"Greenhouse gases" generally refers to gases emitted by electricity generation and other industrial activities that trap the escape of heat from the earth and retain it in the atmosphere and in the oceans. Carbon dioxide is the leading greenhouse gas, causing more than 80% of global warming. Consequently, greenhouse gas emissions are often simply called "carbon emissions."

The concern about greenhouse gas emissions is that the atmospheric and oceanic warming they cause can result in destabilizing events such as higher temperatures, ocean level rise, melting glaciers and ice caps, more energetic and unusual climate events such as storms, floods and droughts, and hotter and dryer timber contributing to forest fires.

Figure 1 shows all of the ways that we can address the problem of changes in climate caused by greenhouse gas emissions.

The principal options are mitigation, adaptation, and geoengineering.

Adaptation refers to ways to adapt to the changes that increased carbon in the atmosphere and the oceans may bring. Geoengineering refers mainly to ways to prevent part of the energy coming in from the sun from reaching the earth. Some adaptation will be necessary because warming will continue even if we reduce greenhouse gas emissions to zero. Accordingly, we should pursue research on geoengineering so that it can be used on an emergency basis if climate change quickly reaches an accute stage.

Of the three options, mitigation is the only way to achieve net zero emissions. Mitigation encompasses both reducing the amount of carbon dioxide and other greenhouse gases that go into the air and taking them out of the air.

There are two ways to reduce (mitigate) the amount of carbon in the air. One is to capture and store or reuse it (carbon capture and sequestration). The other is to stop or slow the emissions.

For achieving net zero emissions, it may be necessary to do both: to reduce the emissions to zero and to draw carbon out of the atmosphere.

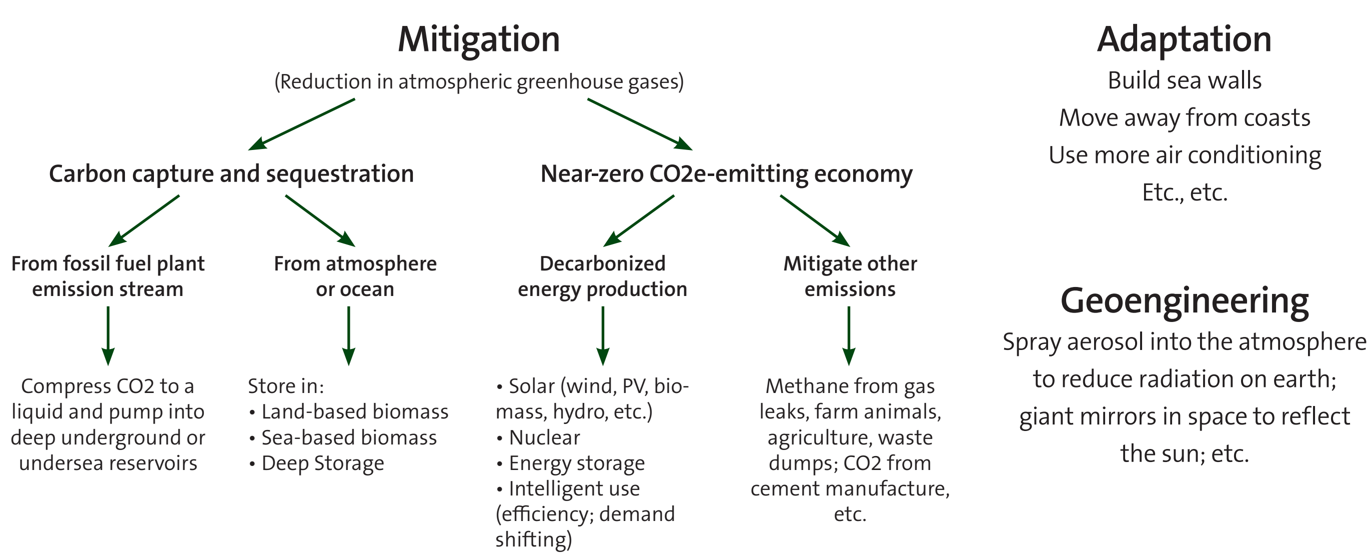
Start with carbon capture and sequestration.

As Figure 1 shows, there are two main ways to capture carbon dioxide and keep it from returning to the atmosphere permanently or at least for a very long time. One is to take it out of the exhaust stream emitted from fossil-fuel-burning power plants and store it deep underground, and the other is to suck it directly out of the atmosphere.

What are the possibilities for both?

Carbon capture from fossil-fuel plant emissions is often abbreviated as CCS, for carbon capture and storage, or carbon

Figure 1. Hierarchy of climate change solutions



capture and sequestration. It involves first capturing the carbon dioxide that forms the main component of the emissions stream from a coal- or gas-fueled power plant or industrial furnace. The carbon dioxide can then be compressed to liquid form and injected into secure caverns deep underground or under the ocean.

If all carbon dioxide could be captured from all fossil-fuel-fired power plants worldwide and stored permanently, it would mostly solve the problem of climate change caused by greenhouse gas emissions (though non-carbon greenhouse gas emissions such as methane and nitrous oxide would still remain). This solution would cause the least disruption to industrial society because we could continue to use fossil fuels as we have for the past 200 years, the period in which almost all technology development and economic growth in the history of the human race has taken place.

What would it take to do that? The coal consumed annually worldwide is currently about 8.5 billion tons, oil 5.3 billion tons and gas 3.1 billion tons, for a total fossil-fuel consumption of 16.9 billion tons.

The quantity of carbon dioxide emitted by burning these fuels is, however, 32.5 billion tons.

Why are the carbon dioxide emissions almost twice as great as the fuels being burned? Because carbon dioxide — CO_2 —is only one part carbon and two parts oxygen. The oxygen is pulled from the air when the fuel is burned. If this CO_2 is buried deep underground, then twice as much oxygen, which came from the atmosphere, as carbon will be buried.

How close are we to being able to implement this much CCS? Right now, the total capacity of CCS in operation worldwide is less than 40 million tons — and these CCS plants are mostly not operating at capacity. They are able to capture and store less than 0.1% of all carbon emissions from fossil fuel plants.

There have been and will be NIMBY (not in my back yard) objections to CCS plants. In 1986, an eruption at a lake in the African country Cameroon released a cloud of hundreds of tons of carbon dioxide, which, being heavier than air, hugged the ground, killing 1,700 people. If there is a semi-irrational fear of radiation from nuclear power plants, there is at least a rational fear of leakage of carbon from deep underground storage. All the federal states in Germany have rejected it. If widespread CCS plants are proposed, there will undoubtedly be local opposition elsewhere, too.

Nevertheless, it is considered one of the major possible solutions to the carbon emissions problem, even / continued page 8

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However, the ruling suggests a way past the section 707(b) issue for independent solar and wind companies. If the power contract is really a lease of the power plant to an independent generator, then there is no sale of goods by the partnership to a related party and no section 707(b) issue. The sponsor is merely renting the power project. The IRS uses a list of factors in section 7701(e) of the US tax code to assess whether a purported power contract is really a lease of the power plant.

In the other ruling, the utility did a more complicated transaction.

It plans to sign build-transfer agreements with multiple developers to buy the project companies and then liquidate them, taking ownership of the assets directly. It will then form two tiers of new entities: holding companies that will turn eventually into tax equity partnerships and multiple shell project companies below each of the holding companies.

According to the ruling, the utility plans to sell each set of project assets to a project company near the end of construction, although it is hard to understand why. Asset sales are difficult because they require assigning contracts. They may also trigger sales taxes that could be avoided by selling a project company.

The utility plans to have each project company sell the electricity from its project into an organized spot market and buy back the electricity it needs to supply ratepayers in the same spot market at market prices, but the timing and quantity of its electricity purchases will be determined by customer demand rather than the solar output from the projects.

The IRS ruled that the projects will not be "public utility property." The electricity from the projects is not sold at regulated rates.

The utility plans to put its capital contributions for a share of project cost into rate base. It plans to recover the amounts it pays in the spot market to buy electricity as a purchased-power expense directly / continued page 9

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though it has not been scaled up to a meaningful level and its costs are still estimated to be very high. But there is optimism that they can be reduced significantly in the future.

Nature-Based Capture

Another proposal is to plant trees to gather up the carbon from the atmosphere. Indeed trees do take up carbon, while they are growing. One can purchase "carbon offsets" from organizations that plant trees and get carbon credits for it.

Planting four trillion trees would take up all the carbon emitted annually worldwide, while the trees are growing. But it would consume 12.3 million square miles, more than four times the area of the United States, and it would compete with agriculture and stop working in about 25 years when the trees reach maturity. What would we do then?

Planting trees absorbs carbon emissions, but stops working in about 25 years when the trees reach maturity.

It has been proposed to sequester carbon in soils by changing agricultural practices. The Intergovernmental Panel on Climate Change estimates that this could remove two to five billion tons of CO2 per year by 2050. This would comprise 6% to 15% of all current CO2 emissions. But soil can become saturated with carbon after 10 to 100 years depending on soil type, climate and management.

Neither of these ideas promises a major and permanent solution to the problem, though both could contribute to the solution on a temporary basis.

Another proposed method of carbon capture and sequestration in biological matter may hold more promise, but it is only in the very early stages of research. Seeding the ocean with chemicals — such as iron — to complete the set of chemical components needed for photosynthesis could cause growth of seaweed and other plant life, which would spur a massive increase in ocean bio-matter, capturing carbon that might then sink to the bottom of the ocean when the sea life thus created dies. But the total potential and costs are unknown, and there are huge questions of possible unintended consequences.

Direct Air Capture

It is possible to capture CO2 directly from the atmosphere that could then be stored deep underground. Technologies to do this exist, but they are currently very expensive.

It would not be the first time that a gas has been captured from the atmosphere to our great benefit. The Haber process, which captures nitrogen from the atmosphere, has enabled the production of fertilizer which has been crucial for the green revolution that produced massive quantities of food in the last 50 years, facilitating population growth and preventing waves of starvation.

But the air is 78% nitrogen. Although there is a lot of carbon dioxide in total, it comprises only 0.04% of the atmosphere. It is a lot harder to capture CO2 from the atmosphere than it is to capture nitrogen.

Nevertheless if the goal is truly net zero carbon emissions, then at least some extraction of carbon from the atmosphere will be necessary, because it will be extremely difficult to bring emissions from some activities, such as cement manufacture and methane emissions from agriculture and farm animals, down to zero.

Decarbonizing Energy Production

The final proposal to decarbonize the economy by bringing its emissions of greenhouse gases down to zero or nearly so has the most potential by a long shot.

Almost all of the emissions of carbon dioxide come from burning fossil fuels, producing energy in coal- and gas-fired power plants, using furnaces for heating buildings and industrial processes, and transporting vehicles.

The only way to bring all of these uses of energy down to zero emissions is to create electricity from zero-carbon sources and then electrify everything. This means that all on-road and off-road vehicles will have to be electric-powered, heating of buildings in most climates will be produced by electric heat pumps, heat for industrial processes will be created directly by electricity or from the waste heat produced by some forms of electric power generation, and ships and airplanes will use electricity or fuels created by electricity, such as hydrogen derived from water by means of electrolysis.

The only non-zero-emission sources of energy are renewable sources such as wind, solar radiation, water power from dammed rivers, biomass, wave energy, nuclear energy and geothermal energy. The most efficient way to use all of these sources of energy is to use them to generate electricity.

This is why the only way to create a zero emission economy is to electrify everything.

What do we need to do to electrify all U.S. energy?

Table 1 shows all of the energy uses in the United States in 2019.

Table 1. Energy uses in the United States 2019

Sector	Quads of energy (10^{15} BTU)	TWh (terawatt-hours)
Electricity	12.9	3,787
Transportation *(except electricity)*	27.9	8,182
Industrial *(except electricity)*	22.9	6,706
Residential *(except electricity)*	7.0	2,058
Commercial *(except electricity)*	4.9	1,432
Total	**75.6**	**22,156**

Source: US Energy Information Administration

Note that electricity currently accounts for less than one-sixth of the total energy use. Use of energy for transportation is currently more than twice our total electricity production.

General Motors has pledged to produce only electric vehicles by 2035. Unless electricity production is ramped up greatly in the next 15 years and all of that ramp-up is produced by zero-carbon-emitting electricity, most of those electric vehicles will run on coal- or gas-fired electricity.

Thus, Biden's pledge to create a carbon-pollution-free power sector by 2035 will put hardly a dent in carbon emissions by then — unless existing power production is / continued page 10

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from ratepayers. The utility will reduce its "cost of service" by the cash it is distributed by the partnership.

There is no section 707(b) issue with the structure because the partnership will not sell any electricity to the utility.

The utility asked the IRS to rule that the projects will not be public utility property. The IRS said they are not such property in the hands of the tax equity partnerships, but that the analysis must also be done at the partner level if the partnerships are able to elect out of partnership status so that each partner is treated as owning an undivided interest in the projects.

The utility represented to the IRS that no such election is possible.

An election is usually permitted where each partner is distributed its share of the electricity in kind to dispose of separately.

The ruling with the more complicated fact structure is PLR 202130005.

XINJIANG issues are getting closer attention from counsel.

Most US companies are now putting language into contracts to require solar panel and battery suppliers and construction contractors to comply with a supply-chain code of conduct.

A typical clause reads, "Contractor will ensure that none of the equipment used in the project was made (or uses material or components that were mined or made) with forced or child labor and that all equipment purchased for use in the project will be able to clear US Customs. Contractor will comply, and will cause each of its subcontractors and vendors to comply, with the SEIA Protocol to ensure that any materials or components originating in the Xinjiang region in western China can be traced through the supply chain."

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converted to zero-carbon emissions and electric power production is greatly increased, and that increase consists mainly of zero-carbon emission electricity.

In order to reach the goal of zero emissions by 2050, zero-carbon-emitting electricity production will have to be increased by a factor of six.

What will that cost?

Table 2 shows estimated costs only for the power generation capacity.

Table 2. Capital cost for zero-emitting power generation capacity in 2050 ($ bn)

	Conservative	Mid-range	Very Low	Land Area (square miles)
Solar	5,616	2,808	2,090	78,000
Wind	4,540	3,404	2,892	195,000 (muliple use)
Nuclear	6,580	4,418	3,948	
Total	**16,736**	**10,630**	**8,931**	

Source: An MIT study published in Joule

The costs for power generation capacity alone will be in the $10 to $20 trillion range.

We are lucky that the costs for solar and wind power generation have declined so much, but the capital cost for the capacity to generate wind- and solar-powered electricity is only a small part of the cost.

Because of the intermittency of those power generation technologies, some means will be necessary to make power available where it is needed, when it is needed, whether or not the wind is blowing or the sun is shining.

We do not yet have a totally reliable and cost-effective solution to this problem. Long-distance transmission lines will help by geographically diversifying the sources of intermittent energy, but also adds a significant cost. If additional storage is needed, currently available solutions may be very expensive. Many trillions of dollars may need to be added to the cost estimates in Table 2 to cover this. Nevertheless, over the next 30 years, innovations and research can solve the problem. But no firm cost estimates can be given at present.

It should also be noted that while installations of wind and solar energy are being ramped up rapidly, zero-carbon-emitting electricity production is still a very small part of total electricity production, especially compared with what will be needed by 2050.

Table 3. 2019 zero carbon electricity production as compared with total need

Source	TWh	% of tot need
Nuclear	824.0	4.5%
Wind	300.8	1.6%
Solar	74.2	0.4%

Source: US Energy Information Administration

Many of the barriers to reaching the 2050 goal are not financial or monetary.

For example, many people, especially in the United States and Europe, do not want nuclear power plants or even wind power plants or high-voltage transmission lines or fossil fuel with carbon capture and storage near them.

Wind and solar power plants use large amounts of land. That land needs to be acquired or leased from someone who already owns it or has supervision over it, and the neighborhood needs to agree or at least not to fight it too hard.

Power plants affect other parts of the environment: wind and solar can harm birds and

An eruption at a lake in Cameroon in 1986 released a CO2 cloud that killed 1,700 people.

animals, nuclear power plants affect waterways, and decommissioning nuclear, wind and solar plants requires waste storage or recycling.

The Bottom Line

Though not impossible by any means, the feat of reaching the goal of net zero carbon emissions by 2050 will be a Herculean undertaking, perhaps comparable to the United States' production surge during World War II, but extended over 30 years instead of five.

A lot can happen in science and technology over 30 years. Therefore, the foremost need is for research and development in science and technology, which must be carried out at breakneck speed even as construction of existing technologies is carried out at breakneck speed.

These are not digital technologies we must construct, but solid structures of heavy metal and other weighty materials, the kind that hurt a lot when dropped on your foot. We have become accustomed in the 21st century to digital innovations proceeding from concept to realization extremely quickly. The technologies needed for the energy transition are very different; they may not be able to move so fast.

But as the moonshot achieved its goal because our aspiration and ambition were great, we may be able to achieve this goal too if we are similarly aspiring and ambitious. ◎

It goes on to require the contractor, if asked by the US developer, "promptly to provide the supply-chain map described in the SEIA Protocol and to allow a review of its records establishing compliance by an independent auditor retained by" the US project developer or its lenders or tax equity investors to confirm compliance.

Any breach is a contract default that allows the US developer to terminate the contract and be paid damages.

Chinese companies continue to insist that there are no forced labor issues in Xinjiang and are taking offense at use of clumsy words in contracts like "foreign adversary country" incorporated from US government orders.

A 36-page "Xinjiang Supply Chain Business Advisory" that six federal agencies issued in July warned that US companies that do not exit supply chains connected to Xinjiang "could run a high risk of violating US law."

Among the statutes referred to in the advisory is a federal criminal statute at 18 USC 1589(b) that makes it a crime to participate in a "venture" that benefited from forced labor either knowingly or with reckless disregard of the use of forced labor somewhere in the supply chain.

The statute could also be used as a basis for a private civil action. The US courts have authority to hear civil cases even though the forced labor was in another country. The burden of proof in a civil action is preponderance of the evidence rather than the beyond-a-reasonable doubt standard that applies in a criminal case.

The best advice is to require vendors and contractors not to use any materials or components made with forced labor, to monitor news reports about potential links and to consider going one step further to require supply-chain maps.

About a third of solar-grade polysilicon used in solar panels in 2020 was manufactured in Xinjiang, the business advisory said.

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Summer Market Survey

Five market veterans had a wide-ranging discussion this summer at the annual ACORE Finance Forum — what used to be called REFF Wall Street conference — about current issues in the market, including how companies are handling forced-labor issues in Xinjiang, inflation, tax equity scarcity, equity returns, carbon capture projects, current discount rates to price M&A bids, capital costs to assume in PPA bids and more. The conference this year was virtual.

The panelists are Himanshu Saxena, CEO of Starwood Energy Group, Gaurav Raniwala, global renewable energy lead at GE Energy Financial Services, Martin Torres, head of renewable power in the Americas for BlackRock, Ja Kao, CEO until April of Blackstone portfolio company Onyx Renewable Partners, and Anand Dandapani, executive director on the tax equity desk at JPMorgan. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Tax Equity

MR. MARTIN: Himanshu Saxena, many companies found it challenging last year to raise tax equity. Was that your experience, and have things improved this year?

MR. SAXENA: For good projects, with good offtake contracts and a good story around electricity basis risk and curtailment, there is tax equity available. Good projects will attract tax equity. Projects that are marginal are going to have a hard time.

MR. MARTIN: Have you seen any change between last year and this year?

MR. SAXENA: We have not had trouble raising tax equity to date. We try to do good projects, and good projects tend to find tax equity.

MR. RANIWALA: I agree. Last year, COVID, for a period of time, scared away some tax equity investors. Most of those investors have come back to the market, in some cases with a broader strike zone and a larger ticket size. There is sufficient tax equity for onshore wind. Solar might be slightly different.

In fact, as we continue to do deals, we are getting inquiries from other tax equity providers asking whether our portfolio is for sale, because there is hunger for more tax equity in the market. Overall, the market is back and fully functioning.

MR. MARTIN: Are you, as GE, investing only in projects that use GE equipment?

MR. RANIWALA: That is correct. Historically, we have been technology-agnostic, but for the past four or five years, we have been focused purely on projects that use GE technology. We try to ensure that any such project has tax equity available to it.

MR. MARTIN: Anand Dandapani, for you it has probably felt like a treadmill moving at rapid speed. JPMorgan is about a quarter of the US tax equity market. Have you seen any difference between last year and this year?

MR. DANDAPANI: It is much of the same. We counted $17 to $18 billion of tax equity raised last year. We are seeing at least as much, and probably more, likely to be raised this year. Let me also add to the earlier comments that well-structured projects that have the technical due diligence well organized are easier to get done. It is hard to get attention from investors for projects that are still early in the development stage.

MR. MARTIN: Ja Kao, did Onyx have any trouble last year raising tax equity?

MS. KAO: We did not. In the large utility-scale space, you have more emphasis on the quality of the project and the quality of the names behind it. For mid-size projects and developers, it is really about the sponsor. For mid-size developers, the tax equity market was either open or it was not open for the last year and a half.

MR. MARTIN: And there is no change today?

MS. KAO: No. [Laughter] Some things never change in the market.

MR. MARTIN: Martin Torres, sponsors last week at the CLEANPOWER 2021 conference said that unlocking ITC tax equity has been a challenge this year for just about everybody. I noticed you invested in a commercial-and-industrial solar platform. Do you agree with that statement and, if so, is it slowing new construction of such projects?

MR. TORRES: The only projects for which we raised tax equity last year were solar projects, and we did not really see any challenges. We were not in the market with utility-scale solar deals. They were smaller portfolios.

MR. MARTIN: C&I solar has been the next big thing for more than a decade, but high transaction costs have been an impediment to getting much traction. Has that situation improved?

MR. TORRES: Yes and no. There has been some consolidation, allowing some platforms and investors to figure out how to do financings more efficiently. So the answer is it probably has improved. At the same time, there are still cost inefficiencies and scaling issues. The fact that there is room for improvement is why we find it an attractive place to invest.

MR. MARTIN: Has anyone else had difficulty unlocking tax equity for projects on which investment tax credits will be claimed?

MR. SAXENA: We saw toward the end of last year and the beginning of this year that certain tax equity investors were looking for deals with production tax credits rather than investment tax credits. Recognition of the full tax credit in one year can obviously be a challenge, especially last year when folks didn't know what their tax appetites would be. There was a logjam of tax equity deals not happening on the solar side toward the end of last year.

That has largely gotten unblocked this year because it is a little easier to forecast tax appetite over the course of 2021 and even beyond with the economy reopening.

MR. MARTIN: Gaurav Raniwala, has it become easier to forecast GE's tax capacity?

MR. RANIWALA: It is never going to be an easy thing to do for a big corporation, but to Himanshu's point, as the economic activity picks up, people are much more comfortable with longer-term PTCs and are able to manage the economics in that context.

Despite COVID last year, we never backed out of the tax equity market. In fact, we had to step in for some banks that had backed away to make sure that GE customers were able to get their projects to the finish line.

It has been working out fine because, like I said, we have been getting inquiries from other investors, so to the extent that we need to manage our own balance sheet, we can manage it by finding other partners at the right time.

New Investors

MR. MARTIN: Obama ironically had little success drawing corporations as new investors into the tax equity market. Trump had more success because the economy was booming. Companies had large profits to shelter. Do you expect to see a lot of new tax equity investors if the gross domestic product grows at a 6% to 8% rate this year?

MR. RANIWALA: We are certainly working in that direction. We continue to engage with multiple potential corporate investors.

The challenge is twofold. One challenge is that this is a complicated product, so it is not easy for corporate finance departments to take on something like this. The other challenge is accounting. The profits come in below the line, which shareholders may or may not understand and therefore may penalize some of these corporations for making good / continued page 14

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US Customs put a "withhold release order" in place in late June to block solar cells and panels containing silica produced by Hoshine Silicon Industry Co. Ltd. from entering the United States.

At least one solar panel supplier reported that US Customs is blocking its panels.

The day before the withhold release order, the US Department of Commerce placed Hoshine and four other companies involved in the manufacture or use of polysilicon products on the "entity list." The four are Daqo New Energy Co., East Hope Nonferrous Metals Co., GCL New Energy Materials Technology Co. and the Xinjiang Production and Construction Corps, also known as XPCC. US and foreign companies are barred from exporting or transferring US-made goods or foreign-made goods with more than a small amount of US content or US technology to companies on the entity list without US government permission.

The US Senate unanimously passed a bill in mid-July that would create a rebuttable presumption that any goods "mined, manufactured, or produced wholly or in part" in the Xinjiang region in western China were made with forced labor and should be blocked from entry into the United States.

The bill identifies polysilicon as a priority sector for enforcement of the new policy.

It would require the government to hold a public hearing within 150 days after enactment about how best to ban products made anywhere in China with forced labor. It directs the government thereafter to publish lists of affected products and companies that export such products to the United States as well as guidance to US importers about what diligence to do and how to trace supply chains.

The bill must still pass the House. A version of it passed nearly unanimously in September 2020, but died when the last Congress adjourned at the end of 2020.

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investments. Both issues need to be solved before we can get a big chunk of corporate business into this market.

MR. MARTIN: Explain what "below the line" means in this context.

MR. RANIWALA: Most corporations are measured on operating profits. With tax equity, the investment return comes in the form of tax benefits taken into account after operating profit. Your operating profit is negative from investing in a tax equity transaction because you are writing off your investment for a period of time through book depreciation, reducing your operating profit, but you earn a return by taking tax benefits over the same period of time.

Renewable energy tax equity investment is expected to reach $17 to $20 billion this year.

The investment might look like a negative investment from an operating profit perspective, but the company is getting all of its investment back and then some on the tax line that comes after operating profit. Shareholders may or may not understand this when measuring a corporation using operating profit as a benchmark.

MR. MARTIN: I thought the reason that the big internet retailers who have done well during the COVID lockdown are not coming into the tax equity market is they can earn more in their own businesses by plowing profits back into them than they can in the tax equity market. Is there any truth to that theory?

MR. RANIWALA: Sure, they can earn a lot more by investing in their own businesses, which are high-risk, high-reward businesses, but most of them are sitting on piles and piles of cash and are looking for ways to invest. Tax equity investments tend not to be high-risk investments. They are reasonably low-risk investments and tax equity definitely gives them a significant increase in yield if the alternative is keeping cash in a bank. The problem is most of them lack the corporate capability to take on the product itself.

MR. MARTIN: Anand Dandapani, you said you think tax equity volume this year will probably be higher than last year. Last year was $17 to 18 billion, as measured by looking at commitments. What do you think the number will be this year?

MR. DANDAPANI: It is hard to say, but we put it at between $17 and $20 billion.

MR. MARTIN: Last year, JPMorgan did about $4.5 billion. Will it invest more this year?

MR. DANDAPANI: I think so. The size of investments has increased. We are doing a lot more solar, and solar project sizes have increased, particularly with the addition of batteries.

MR. MARTIN: Do you have a number: $5 billion, $5.5 billion?

MR. DANDAPANI: Not yet.

MR. MARTIN: Himanshu Saxena, many developers ask what tax equity yields to assume in models when they are bidding to supply electricity. What is the answer this year?

MR. SAXENA: The answer is start with whatever you think is fair and add 200 basis points to it. [Laughter]

Tax equity costs have really fluctuated quite a bit over the past 12 to 24 months. We think they range from the low 6% range for a utility-scale project with a busbar PPA and high-quality, creditworthy counterparty to a number in the 8% range for uncontracted assets or projects with offtake contracts but with significant electricity-basis or curtailment risk in certain markets.

MR. MARTIN: Martin Torres, same numbers?

MR. TORRES: Yes, that's pretty accurate. We have seen a lot more variability. That is probably because projects today exhibit a broader range of risks than they did more than five years ago.

Carbon Capture

MR. MARTIN: The tax equity market is about to have a lot more strain put on it. The first $3+ billion offshore wind project — Vineyard — could be in the market as early as this year for tax equity, although the tax equity part of the financing could slip to next year. Biden wants to complete another 36 offshore wind projects of similar size by the end of this decade. In addition, a lot of carbon-capture projects are coming to market with production tax credits over 12 years of $50 to $150 million per year per project at industrial facilities that emit one to three million tons of carbon dioxide a year.

Are you aware of any carbon-capture tax equity deals that have closed so far? Anyone?

MR. RANIWALA: I heard about one carbon-capture deal that was done a couple plus years ago, but it was focused on enhanced oil recovery, and I think the project may no longer be operating after oil prices crashed.

MR. SAXENA: We have two carbon-capture projects in our portfolio currently. We are looking at many other projects. The number you need to make some of these commercial carbon-capture projects work is significantly above $50 a ton. The number is somewhere between $50 and $100 a ton. It is very challenging to make the numbers work with the tax credit at the current level.

We have heard of two projects — one methanol and one ethanol — that are in an advanced stage, but neither of those deals has closed.

The cost of tax equity for such projects is high. It is high not because the stated yield is high, but because the tax equity investor is looking to share in certain benefits that are unrelated to the tax benefits. These investments are more like true equity than tax equity.

The whole area is new, and people are still figuring out how best to monetize section 45Q tax credits.

Offshore wind projects are likely to claim ITCs and to compete with solar for tax equity. Carbon-capture projects will claim PTCs and compete with onshore wind for the same scarce tax equity dollars. There is not enough tax capacity from what we can tell to do all these projects. Congress is going to have to provide a safety valve through a direct-pay alternative.

The message is that you don't need tax equity in the middle if you are trying to create an incentive. The friction cost of tax equity is just too high to do a carbon-capture project. The structures are too complex and guarantees that the investors will want pertaining to carbon

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The latest House version cleared the House Foreign Affairs Committee on a 25-22 party-line vote in July as part of the EAGLE Act. The House bill does not have the long implementation timeline and opportunities for companies to comment during the rulemaking process that are in the Senate bill. The two houses will have to iron out differences in approach after the House passes its version.

Marco Rubio (R-Florida) and Jeff Merkley (D-Oregon), the two Senators behind the Xinjiang forced labor bill in the Senate, identified three solar panel manufacturers that they said have publicly acknowledged sourcing polysilicon from the region: Jinko Solar, JA Solar and LONGi Solar.

LONGi accounted for about 21% of solar panels entering US ports in shipping containers in Q2 2021, according to research firm Panjiva. Jinko said in a filing last December with the US Securities and Exchange Commission that some products it sells in the US could contain materials from Xinjiang. The filing said the company may have to reconfigure its supply chains if the US tightens restrictions.

The value of all US solar panel imports in Q1 2021 was $2.14 billion, according to the US Energy Information Administration. US solar panel imports during Q1 2021 came 37% from China (including Hong Kong), 19% from Vietnam, 14% from Malaysia and 9% from Thailand. Vietnamese factories have struggled to meet production schedules during the last few weeks due to COVID lockdowns.

Solar panel prices have increased 18% this year, after falling 90% over the last decade, according to LevelTen Energy.

A HOPED FOR EASING OF TARIFFS affecting the renewable energy sector once President Biden took office has not happened.

Two US solar panel manufacturers asked the US International Trade Commission on August 2 to extend US import tariffs on solar panels for another four

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sequestration are not guarantees that most projects can provide. It will be very hard commercially to monetize section 45Q credits.

MR. MARTIN: You said the reason yields for tax equity for carbon-capture projects are so high is investors are looking for more than just tax credits. What else are they looking for?

MR. SAXENA: We have seen everything from sharing LCFS credits in California to sharing in the value of the CO2 that is being sold. Everything is on the table. We have seen some tax equity investors take a view on all-in returns with multiple revenue streams. It is a different mindset than we have seen in solar and wind so far.

MR. MARTIN: Biden proposed in his budget message to Congress in late May to increase the credit amount, but not for ethanol, natural gas processing or ammonia plants.

Direct-Pay Alternatives

MR. MARTIN: Ja Kao, suppose Congress enacts a direct-pay alternative to tax credits? Will that put downward pressure on tax equity yields?

MS. KAO: Yes.

MR. MARTIN: Why?

MS. KAO: I think it will help developers advance projects that are harder and more complicated. There will always be large projects that need an institutional tax equity investor. GE was a tax equity investor long before renewables existed. There have always been tax credits and depreciation. For the large projects, there will always be a tax equity market.

The expansion of the credits requires there to be some other alternatives for new technologies as well as for smaller-scale projects.

MR. RANIWALA: The internal rate of return for tax equity transactions, if you exclude depreciation and just take tax credits into account, is comparable to the cost of debt. The rest of the benefit comes really from depreciation monetization. In my mind, while there might be some impact on pricing, tax equity will continue to add value if done right.

MR. MARTIN: The direct payments will have at least a one-year lag after the project is put in service. Himanshu Saxena, would you go into the tax equity market if you have a direct-pay alternative, or would you borrow to bridge the cash payment and keep the depreciation yourself?

MR. SAXENA: I think those are two separate questions. Borrowing against a stream of cash flow from the government will be the cheapest route. There is no reason to bring tax equity into the middle of that transaction. We have seen this with section 1603 cash grants.

In terms of whether to raise tax equity to get value for the depreciation, that would be case by case. Depreciation accounts potentially for about 10% of the capital stack. If the project economics are tight, then you might need to monetize the depreciation.

Liquidity

MR. MARTIN: Martin Torres, interest rates on back-levered debt in January were somewhere between 125 and 175 basis points over LIBOR, depending on the project. Where are they today?

MR. TORRES: We have not seen spreads widen. The spread depends on the underlying characteristics of the project. Lenders are probably looking differently at underlying revenue contracts after what happened in Texas in February, so some lenders might have a different perspective, but

The US needs a three-fold increase in renewable generating capacity to meet US carbon reduction goals.

the debt market has not changed for projects with power purchase agreements.

MR. MARTIN: Has there been any change in tenors, debt-service-coverage ratios or other terms in the debt market?

MR. SAXENA: We are seeing folks go beyond the PPA term in structuring the debt amortization, which is an interesting evolution in the market. There are not enough good projects for lenders to lend to, so they are taking certain risks that they have not taken in the past to win mandates.

MR. MARTIN: Are you talking about back-levered floating-rate debt or fixed-rate project bonds?

MR. SAXENA: It is floating rate, and the same thing is true whether it is back-levered or at the project level.

MR. MARTIN: *The Economist* magazine said this week that $178 billion flooded into green investment funds in the first quarter this year. That's a global number. Is it getting easier for investment funds focused on the renewable energy sector to raise capital?

MR. TORRES: I don't know that it is getting easier. It is easier to have certain conversations in certain geographies where there was historically more reluctance to invest in the sector, but fundraising is easier or harder based on the track record and experience of the fund manager. That said, investors are more open to sector-specific strategies at this point.

MR. MARTIN: Where is the money coming from?

MR. TORRES: We see money coming from all around the globe. For sustainable ESG-driven clean energy investments, the institutional investors in Europe have long been ahead of the curve on a regionally comparative basis. However, investors across the US and the Asia-Pacific region are all investing behind these strategies.

Renewables Growth

MR. MARTIN: The installed base of renewable energy in the US needs to rise about three-fold in order to meet US carbon reduction goals. Where is the room for such a large increase if demand for electricity remains flat and if states and the federal government are throwing money at nuclear plants and carbon capture credits at fossil-fuel plants to keep them open?

MR. SAXENA: Carbon credits are not going to keep coal plants alive. We have had coal plants come to us for capital to install carbon-capture projects. We don't think there is any appetite for that in the market. If you call JPMorgan and say you need a billion dollars of tax equity to put a carbon-capture project on a big coal plant in the Midwest, they will hang up on you.

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years beyond February 6, 2022 when the current tariffs expire.

The current tariffs were imposed by President Trump in February 2018 at a 30% rate and were originally supposed to remain in place for four years, with scheduled annual reductions to 25%, 20% and 15% over the period. (For more details, see "Tariffs: Effect on US Power Sector" in the April 2018 *NewsWire* and "Suniva Tariffs" in the December 2017 *NewsWire*.) However, last October, Trump increased the tariff in the final year from 15% to 18%. World Trade Organization rules allow the tariffs to be extended by up to another four years, but with continued reductions in rates.

The two companies asking for an extension — Auxin Solar and Suniva, Inc. — asked for "only minimal" future reductions in the rate.

The International Trade Commission has until December 8 to examine whether the tariffs remain necessary to prevent serious injury to US solar panel manufacturers and whether the tariff shield has had a positive effect on US manufacturing.

The decision whether to extend will ultimately be made by President Biden.

Canada is attempting to have the tariffs waived on solar panels made in Canada. It asked a dispute settlement panel on June 18 to address whether the tariffs are allowed under the United States-Mexico-Canada trade agreement.

Meanwhile, the threat of an import tariff on transformers appears to have ended.

The US Department of Commerce announced plans in May 2020 to launch an investigation that could have led to tariffs on imported electrical transformers and their components. The affected components were laminated steel used to make cores, wound cores and transformer regulators.

The investigation was launched at the request of steel company Cleveland-Cliffs Inc., which said other / continued page 19

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There is a lot of inefficient generation in places like PJM. A lot of this is coal; it has to go away. Coal in this country accounts for almost 200,000 megawatts of generating capacity. It is not a small amount of capacity that will shut down over the next five to 15 years. Yes, it is true that the demand is not growing, but we think retirements will accelerate.

MR. MARTIN: You said 200,000 megawatts. That is not a three-fold increase in renewable capacity. That does not leave enough room.

MR. RANIWALA: We are also expecting a significant increase in demand for electricity as the transportation sector electrifies. The expectation is for somewhere between a 50% and 75% increase in demand.

MR. MARTIN: The most recent study I saw projected a 25% increase in electricity demand. However, estimates vary. We held a panel discussion with a number of experts about this two years ago, and the consensus was a mass shift to electric vehicles would shift time of use, but lead to only a negligible increase in electricity demand. Himanshu was there. (For more detail, see "The Shift to Electric Vehicles" in the August 2019 *NewsWire* and "How Electric Vehicles Are Transforming the Power Sector" in the April 2018 *NewsWire*.)

MR. SAXENA: What is the saying: 90% of the facts are made up on the spot? [Laughter]

The studies that I have seen lately point to a significant increase in demand. It could be as much as a 20% to 30% increase.

More importantly, that demand growth will be concentrated in certain places. It will not be uniform. I think buying gas-fired power plants that are close to load centers is the way to go because that is where you are going to see the greatest uptick in demand.

It is like a hotel business. You want to buy a hotel in midtown Manhattan. You may have short-term bumps, but over the long term, you will do fine. Gas has a place to stay.

I think the stories about the demise of gas are vastly exaggerated. If you eliminate gas, you have what we saw in Texas last February and in California this week. There is a 0% chance that in the next 10 to 15 years you can remove gas from the grid. Even the G7 leaders who met last week talked about not financing coal, but there was no mention to cutting off financing for oil and gas. They understand that gas is a key part of the supply chain.

Equity Returns

MR. MARTIN: Ja Kao, Himanshu is always good for epigrams. A couple years ago, he said he planned to have t-shirts printed that said, "Who needs returns when you have solar?" Has there been any improvement or have equity returns in the solar market worsened?

MS. KAO: Oh, that's a loaded question. I think it depends on where you are in the market. The return thresholds for investors have certainly gone down. We can see this in the bidding on projects and portfolios that have changed hands. I think it reflects the competition on the investing side. The returns for middle-market projects are still robust because they are more challenging to finance.

MR. MARTIN: The Economist also said this week, "A mass of money chases a few renewable energy firms. Valuations have been stretched into bubbly territory." The competition for assets is coming not just from private equity funds, but it is also from SPACs, from oil companies, from strategics and from pension funds looking to invest directly. Ja Kao said this is pushing down returns in the solar sector. What effect is this having on discount rates used to price assets in other sectors?

MR. SAXENA: There is an interesting op-ed piece in the Wall Street Journal today that is worth reading about the electric-truck manufacturer Lordstown and the whole stock buyout and resignations of the CEO and the CFO. The SPAC phenomenon, especially as it relates to clean energy and electric vehicles, is way over-bought. (For more details on SPACs, see "SPACs Gain in Popularity" in the October 2020 *NewsWire*.)

We can't compete with SPACs, and I don't think anybody can in buying these companies. We will soon find out whether the valuations SPACs are placing on companies hold. We have already seen some spectacular failures.

The good news is that the SPACs are playing in a sort of quasi-tech sector rather than dealing with hard assets. It is not the same playing field, at least so far.

MR. MARTIN: Martin Torres, what are current discount rates for bidding on assets?

MR. TORRES: It depends on the market segment. They are more competitive for contracted utility-scale solar projects.

MR. MARTIN: Where are they for that type of asset?

MR. TORRES: They are in the 6% to 7% range, depending on what assumptions people are making. It is always tricky to isolate an equity return because somebody's 6% could be somebody else's 9%. It really depends on what kind of assumptions you are making around a project.

We look at equity returns on a relative basis. Utility-scale solar is at the most competitive end of the spectrum, and distributed solar — commercial and industrial and residential — are at the other end of the spectrum. Wind falls in-between, depending on the offtake arrangements.

MR. MARTIN: As a sponsor, you would earn a higher return in the distributed end of the market?

MR. TORRES: For sure.

MR. MARTIN: And that return is in the high single digits?

MR. TORRES: I think you can see returns in the distributed solar sector that are north of high single digits.

MR. MARTIN: Low teens?

MR. TORRES: Low double digits, yes.

MR. MARTIN: If you are sitting on assets today, is this the time to sell, especially if you think tax rates will increase next year?

MR. TORRES: That is a complicated question to answer. It depends on your overall investment strategy. If it is to earn a maximum return for having capital deployed for a short period of time, the answer could be yes. If your objective is to keep capital deployed for an extended period of time, then the answer is not necessarily yes because then you have to look at the reinvestment universe.

If you are anywhere close to needing or wanting to sell assets, this is a good market for that. If you are going to have to redeploy that capital in the same sector, then you have to take a much more nuanced view and consider the investment opportunities at the time.

MR. MARTIN: It is like selling your house today in a hot market, but then not being able to buy a new place to live.

Inflation

MR. MARTIN: Let me go back to Anand Dandapani. There has been an uptick in the last two months in inflation. Are inflation concerns starting to affect the market and, if so, how?

MR. DANDAPANI: Not the tax equity market. We are not seeing pressure on yields due to inflation. However, the overall return on a project might be affected. Spiraling costs have the potential to affect sponsor returns significantly.

MR. MARTIN: Gaurav Raniwala, same answer?

MR. RANIWALA: Yes. From a tax equity perspective, inflation concerns are not really affecting pricing because the underlying Treasury yields are not really changing.

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countries are evading US import tariffs on steel by sending electrical steel through Canada and Mexico where it is incorporated into downstream products like transformer cores that are shipped to the United States duty free under the United States-Mexico-Canada trade agreement. (For more details, see "Possible Transformer Tariffs Under Review" in the May 2020 and "Multiple Tariff Issues in Play" in the December 2020 *NewsWire*.)

Cleveland-Cliffs said the imports would force it to close two steel mills in Butler, Pennsylvania and Zanesville, Ohio, two key battleground states in the US presidential race in 2020.

Trump took no action ultimately. The Biden administration released the Commerce Department report that was sent to Trump concluding that the imports are a threat to US national security and recommending that tariffs be imposed.

The 360-day deadline for the president to impose tariffs or other import restrictions in the transformer case has passed.

Separately, the US imposed a 73% anti-dumping duty in early August on wind towers imported from Spain. It had already imposed a 6.4% countervailing duty in July on wind towers imported from Malaysia, and is poised to impose a tentative 54.03% countervailing duty on wind towers from India sometime in August. (For earlier coverage of tariffs on wind towers from Canada, Vietnam, Indonesia and South Korea, see "Unpredictable Tariffs" in the February 2020 *NewsWire* and "Solar and Wind Tariffs" in the December 2019 *NewsWire*.)

The US has six domestic wind tower manufacturers in nine states who collectively employ 2,205 workers. The US spent $1.8 billion on wind towers in 2020, of which $955 million were supplied by US manufacturers, according to US International Trade Commission data. Malaysia, India and Spain are the three leading foreign suppliers.

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However, on the industrial side of our business, we are not immune to the commodity-side pressures that are being faced by manufacturers everywhere. Our teams are working constantly on different ways to minimize cost and examine what commodities they use. Renewables are going to grow, given where government policy is headed, but this could be a sharp bump in the road that the industry will have to work through.

MR. SAXENA: The cost of solar panels, for the first time in a decade, has gone up. We are seeing similar pressure on wind turbines. We are building a big transmission project, and we see this pressure on copper, steel and lumber.

Escalating costs have the potential to affect sponsor returns significantly.

Tax equity will not fund more, so this is not a tax equity problem. If the project cost goes up by 20%, the additional cost will come out of the cash equity. The returns will get stressed if power prices have already been locked in.

This is a challenge the industry will face, not just in renewables, but also across the board over the next 12 to 24 months before the supply chains normalize.

MR. RANIWALA: We have seen sponsors try to renegotiate the electricity prices to make projects work during periods like this. It is in everyone's interest to do so if they want to see these projects built.

MR. MARTIN: Let me ask two more questions quickly, if we have time.

Pressure is mounting to block entry of solar panels that use materials from the Xinjiang region in western China. The Solar Energy Industries Association issued a tracing protocol in April that it recommends solar companies adopt when buying solar panels. Are concerns in this area affecting the choice of solar panel suppliers, and how is the risk that a withhold release order will be issued by US Customs to block panels with any connection to Xinjiang from entry being handled in financings?

MR. DANDAPANI: We are monitoring this, but as you will probably appreciate, we think of this more as a sponsor risk. When it comes time to invest tax equity, the project is already close to completion and the panels are in the United States.

MR. MARTIN: This seems like one of a number of items that are turning out to be sponsor risks this year. It is not just this, but also change-in-law risk in Texas, escalating casualty insurance premiums, and so on.

Himanshu Saxena, what effect has the Texas cold snap had on the ability to finance projects in Texas?

MR. SAXENA: It depends on the type of project. If you have a Texas project with a busbar PPA with a creditworthy utility, there has not been any effect. If you are trying to raise tax equity for a wind project with a fixed-shape hedge, that has gotten really hard.

Norton Rose Fulbright

MR. RANIWALA: Sponsors are probably not interested in doing a fixed-shape hedge today, given recent experience. It is not just the tax equity who have run away from them.

MR. MARTIN: Last question. Casualty insurance premiums for solar projects have increased by as much as 400% in the last two years. Some sponsors have notified tax equity investors and lenders that they cannot find insurance at an affordable price. To what extent are climate-related issues like this affecting the ability to finance projects in places like California, that are at risk for wildfires, or along the southeastern coast and the Texas Gulf coast that are susceptible to freak weather events?

MR. DANDAPANI: We see these issues on pretty much every project. We need to understand what insurance we are getting, what cash provisions can be made to ensure payment of premiums and, if we are not getting the full coverage we normally expect, what happens if there is a casualty and the cash reserves are not enough to get us to our yield. ◎

IN OTHER NEWS

STALLED CARBON CAPTURE PROJECTS started advancing again after an IRS revenue ruling on July 1

The United States offers large tax credits under section 45Q of the US tax code for capturing carbon oxide emissions and putting them to one of three uses. The three uses are secure storage underground, use for enhanced oil recovery and permitted commercial uses.

The tax credits are currently $34.81 a metric ton for carbon emissions stored permanently underground and $22.68 a metric ton for captured carbon emissions put to other uses. The amounts increase annually and will reach $50 a ton for underground storage and $35 a ton for other uses in 2026. (For more detail, see "Tax Credits for Carbon Capture" in the February 2021 *NewsWire*.) Congress is considering increasing them as well as making other changes. (For more detail, see "Wyden Bill and Tax Credits" in April 2021.)

The tax credit was originally enacted in 2008, but it was hard to count on the credits when planning a project because total tax credits nationwide were subject to a 75-million-ton cap. Thus, no industrial company or tax equity investor could be certain for how long it would be able to claim tax credits.

Congress increased the dollar amounts and eliminated the cap in early 2018. (See "Tax Equity and Carbon Sequestration Credits" in the April 2018 *NewsWire*.)

No tax equity deals have closed yet involving the new credits. However, a number of deals were moving forward after the IRS issued final regulations in December 2020 to implement them.

Two issues have come up since then that put deals into a holding pattern.

The tax credits belong to the party who owns the carbon capture equipment. The IRS defined carbon capture equipment in the regulations to include gas separation units inside factories that separate carbon dioxide and other */ continued page 23*

How Banks Evaluate Energy Storage

by James Wright, with CIBC Capital Markets in Chicago

Banks have been ready to finance batteries for a while, but until recently, they had not seen many deals come across their desks in need of financing.

The market is changing rapidly.

First, the basic economic case for them had been marginal until recently. Engineers talk about a learning curve for any new technology, which is the cost decline as a function of deployment volumes. This compares favorably with batteries to what bankers saw earlier for wind and solar. Battery costs have declined significantly in the last couple years.

Second, a more favorable regulatory environment is taking shape in many states as utilities put batteries in their plans for capacity build outs. It has only been three years since the Federal Energy Regulatory Commission came out with Order No. 841 that gave a lot more tailwind for battery storage rolling out across organized markets.

Third, the banks had to go through a bit of education on the financing side about the storage landscape and the complexity of the various usage cases: in more basic terms, the number of ways that batteries can be used and how they fit into the broader market.

Finally, it has been a hot renewables market the past few years, and bankers have been so busy with regular wind and solar deals that there was no need to branch out. All of that has now changed. Practically every solar deal today is solar-plus-storage. Banks cannot duck it. They have had to master batteries to remain relevant.

Comfort

Banks like historical data to help assess risk, risk-weighted cost of financing and debt-service-coverage ratios. There is not a lot.

The US Department of Energy reported recently that only 14 utility-scale batteries have been operating for more than 10 years. That is not just in the US, but globally.

Lenders have been getting comfortable by taking deep dives into the basic chemistry and finding comfort there. About 90% of storage deals that come across our desks involve lithium-ion chemistry. This form of battery has been around for a long time. It dates back to the 1970s and was first commercialized by Sony in the 1980s.

A lot of what comes across bankers' desks are augmentation use cases. A solar project is generating during peak hours of the day, the sun goes down and then the battery kicks in for another four hours.

Many of the deals bankers see have power purchase agreements with capacity payments, which is helpful from a financial perspective.

The way banks approach these deals has been similar to the typical solar deal with a long-term offtake contract, but coverage ratios have started to diverge recently. Capacity deals are arguably more like an availability type of construct, so all the owner needs to do to earn revenue is to have the battery on and available for use. That means there is not a lot of resource risk. Debt-service-coverage ratios for availability deals are around 1.2x, meaning the projected revenue needs to be around 1.2 times debt service.

The deals are using typical mini-perm, back-leverage types

Only 14 utility-scale batteries have been operating anywhere in the world for more than 10 years.

of structures. The debt sits behind the tax equity in solar-plus-storage deals, and typically banks are being asked to monetize the full value of the PPA (or beyond).

Warranties and service contracts are important. There is a performance obligation lasting 15 to 20 years in the power contract. There has to be some fundamental backup for that from the battery manufacturer. Most deals banks have seen recently have had 10- to 15-year-plus warranties supporting them.

Sponsors are being careful to budget for required future costs to augment the batteries. Cells age over time and must be augmented to ensure the batteries hit required capacity levels for the full 15- or 20-year term of the PPA.

Some sponsors want to bill more for power in the early years to build up a reserve quickly. Others prefer to add to reserves over time.

Usage Cases

The usage cases fall into two buckets.

Bucket one is where storage is used by a utility or grid operator to supply capacity at a certain time of day. That feels like a strategic asset to a lender. Those usage cases typically have high levels of predictability in terms of operational dispatch, which lenders love. The banks then focus on the operating assumptions with the independent engineer because the battery is in a well-defined dispatch box in terms of how it will be used.

The second bucket is where batteries are being used as more of a standalone business. The revenue is largely from providing ancillary services to the grid or earning an arbitrage return. These deals have more unpredictable revenue profiles, making them harder for the project finance market to take a long-term assessment. Banks have been taking more merchant risk in wind and solar deals as they see proof of concept deployed at capacity across the grid. It will probably take a little time before true merchant plays with batteries become primetime in the project market.

Leverage is typically around 90% of value for capacity-type deals in bucket one.

Pricing for such deals is currently at a small premium over regular solar deals. Lithium ion is a well-known technology and most such deals involve bigger sponsors, with robust fundamentals of the underlying PPA and performance warranties. These are the types of factors that typically support high leverage.

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gases as part of the manufacturing process.

This equipment is part of the factory. It is hard to isolate and transfer ownership to a tax equity investor so that it can claim tax credits.

The other issue is the time period for claiming tax credits. It is 12 years from when the capture equipment first went into service or, if later, 12 years after February 9, 2018.

The fact that part of what the IRS considers capture equipment is already in place means that as much as half the tax credit period will already have run for anyone planning a new project today. It takes two to three years to get permits for, finance and build CO_2 pipelines and wells to bury emissions underground.

The IRS said in Revenue Ruling 2021-13 on July 1 that the legal entity claiming tax credits does not have to own all of the capture equipment. It is enough for it to own just "one component" of the carbon capture process train, as long as the entity is legally responsible for disposing of the CO_2.

It is unclear where tax equity counsel will draw the line ultimately, but most people are unlikely to feel comfortable relying on ownership of just a small piece of the process train.

The IRS also said that the 12 years will start to run when the "new components of capture equipment are added" to allow the carbon emissions to be captured, processed and prepared for transport to a disposal site or other use.

Section 45Q credits cannot be claimed in a year unless a minimum amount of CO_2 is captured. At least 500,000 metric tons of CO_2 a year must be captured at a power plant to qualify for any tax credits. The minimum is 100,000 metric tons a year for other industrial facilities. However, for industrial facilities that emit fewer than 500,000 tons a year, the minimum threshold is treated as having been reached if at least 25,000 metric tons of CO_2 a year from the facility are put to permitted commercial uses.

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Energy Storage

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Long Duration

The focus until now has been exclusively on batteries with a four-hour or less duration window. Lithium ion struggles to be the chemistry of choice for longer dispatch cases. California has been doing modeling that shows by 2045 to 2050, the state will need a lot longer duration storage to support the big renewables buildout expected, especially as gas peakers are taken off line.

Within the last couple of months, some California community choice aggregators have issued procurements for eight-hour storage. The bids coming in are for pumped-storage hydro, compressed air and chemical battery solutions. These CCAs want the ability to replace gas peakers, which requires the ability to draw on stored electricity from about 4 p.m. to the next morning.

Other states like New York are also looking at long-duration usage cases, but such usage cases are still at an early stage and we are not seeing them yet in the project finance market.

There are other global examples where longer-duration storage is being looked at as an alternative to transmission line upgrades or as a way to avoid solar curtailment in the summer with dispatch of the stored power months later in the winter.

Some interesting technologies are being tested, such as flow batteries, gravity-based solutions and cryogenic air solutions. Most are still in the demonstration phase, but banks are helping to innovate more credit solutions coming to market and, with the right regulatory support, we expect to see some of these newer battery chemistries also approaching the project market.

Congress is talking about tax credits for standalone storage and other forms of support such as a push to electrify the transportation sector. Any major push to deploy recharging networks will strengthen the case for more storage on the grid to address load mismatches between time of peak use and intermittent supply from renewables. Energy storage could also be a key piece of grid resiliency. Wider storage deployment would have made a difference last February during the four-day cold snap in Texas. The big picture points to a growing role for storage. ◎

Debt-service-coverage ratios have started to diverge for different types of storage projects.

FERC and Congress Tackle Transmission

by Caileen Gamache and Randi Rymut, in Houston

The Federal Energy Regulatory Commission is addressing transmission reform for the first time in roughly a decade, and Congress is helping to relieve legal congestion.

FERC asked for comments in mid-July on an "advance notice of proposed rulemaking" that would make changes to improve electric regional transmission planning and cost allocation procedures and the generator interconnection process.

Transmission development is ripe for review. Although utilities have a formal planning process designed to forecast and address transmission needs, much of the actual transmission build-out is reactionary because it is based on individual generator interconnection requests. The two processes are largely uncoordinated. Developers in many regions have lamented recently that the cost and time for completing interconnection is unreasonable. It sounds like FERC agrees.

FERC acknowledged in the advance notice that the generator interconnection process is probably not the most efficient or cost-effective method to plan a transmission grid that will support future generation. The process focuses on one (or a cluster) of proposed generators in a planning bubble based on technology, location and other specific factors, without taking a broader view of system requirements that could support multiple future generators. The objective of the advance notice is to plan better for the increased interconnection demand while still maintaining just and reasonable rates for customers.

The many specific questions posed in the advance notice suggest a major shake-up in generator interconnection procedures may be in the queue.

For example, FERC is seeking comments on:

1. Cost allocation

FERC directed in Order 1000 that the cost of transmission infrastructure must be allocated among entities using the transmission grid in a manner that is approximately commensurate with the benefits each entity derives from the infrastructure. The advance notice admits that the current cost allocation that occurs through interconnection */ continued page 26*

IN OTHER NEWS

Direct air capture facilities must capture at least 100,000 tons a year.

According to EPA figures, 54% of power plants and 75% of industrial facilities fall short of these minimums.

The Senate Finance Committee voted the last week in May to replace the volumes with percentages. A power plant would have to capture at least 75% of emissions that would otherwise go uncaptured. Industrial facilities would have to capture at least 50%. These percentages work for factories in some industries, but not others.

The committee also voted to increase tax credits for direct air capture to $175 a metric ton. A paper by a professor at the University of California, Riverside, Mihri Ozkan, calculated that a plant using liquid-solvent direct air capture would require 300 megawatts of electricity on a constant basis to capture one million tons of CO_2 a year. If solar electricity were used with storage, it would cost between $430 and $690 per ton of CO_2 captured to run the direct air capture facility. Geothermal energy would bring the cost down to as little as $250 per ton of CO_2 captured.

Other analyses have put the cost of direct air capture at between $100 and $232 per ton of CO_2 captured once the technology is better established.

Separately, the Senate Energy Committee voted in July for $500 million in grants in each of the next five fiscal years, starting with the fiscal 2022 year that begins in October 2021, to be made through the US Department of Energy to fund "new or expanded commercial large-scale carbon sequestration projects and associated carbon dioxide transport infrastructure, including funding for the feasibility, site characterization, permitting, and construction stages of project development."

Priority will be given to projects with "substantial" underground storage capacity or that store emissions from multiple carbon capture facilities. */ continued page 27*

Transmission

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procedures may not satisfy this standard. The current approach might also lead to speculative interconnection requests that waste resources because cost allocation is so dependent on timing and location that some developers may submit "feelers" to assess multiple options for a single project. FERC welcomes proposed revisions. Proposals should address reliability impacts, if any.

The government machinery to address transmission is starting to turn.

2. Future transmission needs

The advance notice also asks for comments about whether transmission providers should amend their regional transmission planning processes to incorporate the transmission needs of anticipated future generators. This would involve anticipating how technology is changing and where future projects might get into interconnection queues, with an express focus on how the role of future federal, state and local climate and clean energy regulations and goals should be considered. Currently, with a few exceptions, regional transmission planning is based on generators in the interconnection queue that have completed facilities studies. This results in a narrow, short-term view of future transmission needs. Among the specific questions FERC poses is how far into the future the process should look and what inputs and assumptions should be modeled. The responses should be interesting given how unpredictable the future generation mix may be in light of the recent meteoric rise in new technologies.

3. Interregional coordination

Transmission planning based on interconnection requests also results in a locationally-constrained view of transmission planning. FERC suggests this approach may impede the development of efficient, cost-effective interregional projects and asks for suggestions.

4. Coordination between interconnection and transmission planning

FERC asks whether it should require transmission providers to coordinate regional transmission planning and cost allocation procedures and generator interconnection processes on concurrent, coordinated time frames. This has the potential to reduce costs significantly that are allocated to a single project.

Anyone interested in providing comments is invited to do so in FERC Docket No. RM21-17. Comments are due Monday, October 10, 2021, and reply comments are due Tuesday, November 9, 2021.

The advance notice repeatedly asks commenters to address whether FERC has the authority to implement suggested changes. Congress is trying to answer that question in part by extending FERC's authority over transmission.

Congress

The US Senate approved a "once-in-a-generation" bipartisan infrastructure package in early August that includes a $73 billion investment in transmission infrastructure to facilitate growth of the renewable energy industry.

Perhaps even more meaningful than the money, the deal would also augment FERC's transmission siting authority. Currently a single state can block a regional transmission project, even if adjacent states support the project.

The bill proposes to change that if the project is sited along a "national interest electric transmission corridor." The US Department of Energy defines these corridors as regions where the public would benefit from additional transmission due to congested power lines coupled with high demand. FERC currently has this authority over siting of gas pipelines, so there is precedent for this proposal. The consolidation of siting authority could in and of itself help advance transmission infrastructure because it would reduce development risks. States have understandably objected to the idea.

The advance notice and proposed infrastructure bill are subject to revision and the actual impact is impossible to predict. They both reflect changes in generation technology, new clean energy policies and the reality that the current electricity grid is aging.

It is reasonable to expect that some version of meaningful transmission reform will emerge from all of this that will affect project developers and lenders. ◎

IN OTHER NEWS

FOUR CALIFORNIA CCAS that are planning to use a form of prepaid power contract may find the structure hard to implement.

A joint powers agency called the California Community Choice Financing Authority formed by the four said in a July 29 press release that it will help the CCAs reduce their electricity costs by 10% or more by borrowing at tax-exempt rates to enable the CCAs to prepay for electricity under long-term power purchase agreements.

CCAs — short for community choice aggregators — are county-level entities in California and some other states that buy electricity to supply to local residents. By buying in bulk, they hope to secure better electricity rates than the retail rates that local residents would otherwise pay the local utility. They may also make it a priority to buy renewable electricity.

A number of municipal utilities signed long-term contracts in the early 2000s to buy electricity from wind farms in which they agreed to prepay for a large share of the electricity. The contracts were structured so that the project owner would not have to pay taxes immediately on the prepayment.

From the standpoint of the project owner, the prepayment had many features in common with cheap long-term debt. The money was raised in the tax-exempt bond market. It could be repaid over the power contract term. It filled a slot in the permanent capital stack for the project. The utility making the prepayment had a first lien on the project. The prepayment was worked off as electricity was delivered over time. The project owner reported the prepayment as income over the same period as electricity was delivered. (For more details, see "Prepaid Power Contracts" in the September 2012 *NewsWire* and "Green Light for Prepaid Electricity Deals" in the August 2003 *NewsWire*.)

Special rules in the IRS regulations at the time allowed this type of arrangement. If the prepayment had had to / continued page 27

N-GEO Futures

by Christine Brozynski in New York, and Noam Ayali in Washington

Nature-based global emissions offset futures contracts are a new type of standardized futures contract being offered on the Chicago Mercantile Exchange that can be used by companies to lock in the cost of carbon offset credits that they expect to need to offset future carbon emissions.

The carbon offset market matches companies that have reduced carbon emissions with others who want to buy credits to cover the emissions they are unable to eliminate.

A private market has developed in carbon offset credits.

Trading started this month in futures contracts that deliver nature-based reductions in carbon emissions.

The Chicago Mercantile Exchange, or CME, is attempting this year to standardize the trading contracts. Each futures contract is a contract for delivery of a specific quantity of offset credits on a future date at an agreed price. The contracts provide greater transparency for carbon offset trades and make it easier for companies that know they will need offset credits in the future to lock in the price.

Nature-based global emissions futures — called N-GEO futures — require delivery of a specific quantity of carbon offset credits on a future date that the seller will have earned for planting trees, preserving a forest that would otherwise be cut down and similar actions. N-GEO futures began trading on the CME earlier this month.

They are similar in construct to global emissions offset futures contracts, called GEO futures, that began trading on the CME in March.

Standardized contracts and a publicly available spot price significantly lower the barrier to entry for companies looking to buy and sell carbon offsets.

Some companies with carbon emissions have started expressing a preference for certain types of offset credits over others.

The number of carbon offset credits arising from nature-based projects has been increasing at a faster rate in recent years than from other actions. This is perhaps predictable given the higher cost and difficulty of using technology to remove carbon from the atmosphere or of altering a company's operations to reduce carbon emissions.

However, it also fits with the priorities of climate scientists who want to preserve vital ecosystems before it is too late.

GEO futures cover all qualified carbon offset types, and the spot price listed on the CME for GEO futures is a single price that does not differentiate among the offset methodologies. N-GEO futures let companies buy and sell nature-based carbon offsets exclusively if they prefer, for a price that reflects that particular type of offset rather than all carbon offsets.

Improved Transparency

This is an area filled with acronyms and its own jargon.

Carbon offsets traded in the N-GEO futures market must meet two standards. They must qualify as "VCS AFOLU projects," and they must be certified under climate, community and biodiversity standards, called "CCB standards," that are administered by an alliance of industry groups.

In contrast, emissions credits traded using GEO futures contracts merely need to be eligible under a "carbon offsetting and reduction scheme for international aviation," called "CORSIA."

VCS AFOLU projects are those that qualify for offset credits under a standard administered by Verra, a non-profit organization devoted to regulating quality in carbon offset markets. Verra stands for "Verified Carbon Standard," and is sometimes shortened to VCS.

"AFOLU" stands for agriculture, forestry and other land use.

The following types of forestry projects qualify as VCS AFOLU projects: afforestation (the act of creating a forest where none previously existed), reforestation (the process of shoring up depleted forests) and revegetation (the act of restoring soil and natural vegetation on barren land), improved forest management and reduced emissions from deforestation and degradation (commonly abbreviated as "REDD").

The following other projects also qualify: agricultural land management, avoided conversion of grasslands and shrub lands, and wetlands restoration and conservation.

VCS AFOLU projects must involve certain approved carbon reduction methodologies. Any methodology approved or developed by either the Climate Action Reserve, an environmental organization in Los Angeles that focuses on the integrity the North American carbon offset market, other than its forest protocols, or the United Nations clean development mechanism is acceptable. Project developers can also develop their own methodologies and submit them to Verra for approval.

The CCB standards were developed by numerous industry groups that refer to themselves collectively as the Climate, Community & Biodiversity Alliance, or "CCBA" for short. Any project design must be approved by the Alliance in advance, and the CBBA sends auditors to visit the project after implementation to confirm that the project provides the benefits claimed by the developer. The auditors also visit with the local communities and invite their comment.

Carbon offsets from projects as far back as 2016 are eligible to be traded under N-GEO futures contracts.

Contract Specifications

N-GEO futures contracts are structured like futures for any other commodity. When a buyer purchases a future, that buyer is agreeing to purchase the commodity on the specified future date. The price of the commodity is locked on the date of the trade. Any upward movement in the market price of the commodity after trade date is considered beneficial to the buyer, as the buyer will ultimately be delivered the commodity for a below-market price. Downward movement in the market price is a boon to the seller, as the seller will presumably offload the commodity on the sale date for an above-market price.

Many traders enter into secondary and tertiary trades by re-selling futures contracts before the maturity date when the commodity must either be physically delivered or the contract must be financially settled. This type of trading require a liquid market with transparent pricing and robust reporting and tracking mechanisms to ensure that commodities are not double counted.

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be reported by the project owner as income immediately upon receipt, then it would have left a hole in the capital stack.

Congress repealed the provision that allowed deferral of the prepayment income at the end of 2017 and required that the remaining unamortized prepayment amounts under such contracts had to be reported as income over the next four years. (For more details, see "Final Tax Bill: Effect on US Project Finance Market" in December 2017 and "Prepaid Power Contracts Harder To Make Work" in the December 2018 *NewsWire*.)

In 2019, the IRS issued regulations that may have reopened the door to use of the structure, at least in cases where contracts are structured to fit in a "specified goods exception" that allows manufacturers in certain cases where goods are paid for more than two years in advance to defer reporting the advance payments as income. However, the regulations left key unanswered questions. (For more details, see "Prepaid Power Contracts: New Lease on Life?" in the October 2019 *NewsWire*.)

A practical challenge with the structure today is the tax equity market is generally no longer open to financing projects with senior permanent debt that sits ahead of the tax equity in the capital stack. Most utility-scale renewable energy projects are financed in that market.

The four CCAs behind the California Community Choice Financing Authority are Central Coast Community Energy, East Bay Community Energy, Marin Clean Energy and Silicon Valley Clean Energy.

PROJECTS ON FEDERAL LAND are probably not be exempted from local property taxes, but it depends on the facts.

A solar company lost another round in court in July in an effort to avoid having to pay property taxes on a utility-scale solar project inside Eglin Air Force Base in Florida.

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N-GEO Futures

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The specific terms of N-GEO futures contracts are similar to those of GEO futures contracts.

N-GEO futures are a right to 1000 environmental offsets per contract. An offset is equal to one metric ton of carbon removed or reduced from the atmosphere. The tick, or smallest increment of price movement permitted with respect to a trade, is $10. This is equal to 1¢ per carbon offset unit per contract. The contracts are available for all month-end dates in the current year and the next three calendar years.

N-GEO futures are subject to customary limits on trading. For example, all participants in the market are subject to position limits to prevent a single entity from controlling too great a share of the market. These position limits are governed by the New York Mercantile Exchange and can be found on the CME website.

Counterparties are permitted to undertake "block trades." A "block trade" is a trade that is privately negotiated between two parties rather than in the public auction market. Block trades are typically subject to minimum transaction size requirements. Both parties must be "eligible contract participants" under the Commodity Exchange Act in order to execute a block trade. Block trades must be reported to the CME.

Unlike GEO futures, for which three different registries may be used, N-GEO futures must all be reported to the Verra registry.

Market Impact

The ability to trade N-GEO futures contracts should lead to a more efficient market. Companies desiring to buy and sell nature-based offsets specifically, as opposed to carbon offsets generally, will now have an avenue to do so. The market will be able to assign a value to nature-based offsets specifically as reflected by the CME spot price, rather than lumping all carbon offsets under a single market price that may not fully reflect the diversity of the underlying offsets.

The CME plans to list spreads for GEO and N-GEO futures, which will allow for inter-commodity spread transactions. This may prove useful for traders looking to manage (or capitalize on) price volatility between the two types of contracts.

Because the standards for sourcing carbon offsets for N-GEO futures are high, companies can be assured that the offsets are of good quality. The fact that the projects are audited by the CCBA may bring comfort to companies apprehensive about accusations of "greenwashing."

However, nature-based projects also have critics. Critics argue that nature-based offsets will do little to curb climate change if not paired with efforts to reduce fossil-fuel usage and its harmful effects, for example by wider adoption of carbon capture technology.

There is some concern that nature-based offsets permit companies to tout their carbon reduction efforts without critically examining how their own practices contribute to a global rise in temperatures. ◎

Landco Structures

by Richard Susalka, in New York

Investors are finding value in establishing "landcos" to own project sites and lease them to project companies.

Investors are in it for the returns. This is especially true in the renewable energy market, where a crowded group of lenders and investors faces tightening margins.

Developers are also using landcos to separate ownership of project sites from the rest of the project, even where there are no outside investors on the landco side of the transaction.

Attractions

Landcos represent an unusually secure investment for outside investors. Landco owners are spared many of the investment risks that project owners customarily accept.

Project owners typically finance their projects with third-party debt and, when doing so, pledge all of their rights to the project as collateral. Project cash flow is used to pay debt service, but it can fall short in various circumstances, many of which are outside of the control of the project owner. If there is a default on the debt, the project owner risks losing the project in a foreclosure.

Even when there is no default on the debt, the project owner's access to equity distributions from the project can be limited or blocked. The share of project revenue available for distribution to the project owner can be reduced by cash sweeps in favor of the lender. Project owners typically accept springing distribution blocks if certain conditions are not satisfied — including, for example, if the project fails a minimum debt-service-coverage-ratio test.

If a share of project revenue is paid as rent for use of the site and thus routed through a landco, the landco owners are generally spared those risks.

Site rent payments are treated as an operating expense. Operating expenses are usually paid ahead of debt service.

Even where a lender forecloses, rent payments are likely to continue for as long as the project requires access to the site.

There are scenarios in which site access may no longer be needed, such as after a catastrophic casualty where a decision is made not to restore the project. Such scenarios are remote. A landco owner wishing to limit its downside in such a scenario could negotiate provisions to do so in the lease.

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The solar company owns the project. It subleases the 240 acres of land underneath the project from the Gulf Power Company, which in turn leases it from the US Air Force.

The company argued that the state cannot collect property taxes on a project inside a US military base.

It lost in the trial court. It lost again in a state appeals court.

The appeals court said the Military Leasing Act — the federal statute that authorizes the US military to lease surplus land to private parties — says the "interest of a lessee of property leased under this [statute] may be taxed by state or local governments."

If that were not enough, the 1951 deed under which Florida ceded land to the US government for use as a military base said the property is exempted from Florida property taxes while it remains "owned and occupied by the United States" for the purposes in the deed and "not otherwise."

The case is *Gulf Coast Solar Center I, LLC v. Busbee*. The appeals court released its decision on July 19.

Last October, a New York appeals court held that property taxes must be paid in New York on a private solar project that sits on land leased from Cornell University. Cornell is not subject to property taxes, but the court said it is not the owner of the solar project. (For more details, see "Solar Projects and New York Property Taxes" in the October 2020 *NewsWire*.)

In some states, developers use PILOT statutes as a way to put ownership of projects nominally in state hands. This avoids not only property taxes, but also sales taxes on equipment purchased for use in the project in some cases. The developer pays a negotiated property tax amount each year. "PILOT" stands for payments in lieu of taxes.

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Landcos

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Landco investors will be able to hold on to the site even if the project is thrown into foreclosure. Project financiers will require the right to use the site to be pledged as part of a project financing and thus be subject to foreclosure after a debt default. If the project owner merely leases the site, its leasehold interest is likely to be transferred as part of the foreclosure, but ownership of the land will remain with the landco.

Opportunities

A developer who is short on cash can identify sites for its projects, but find an outside investor who is interested in owning sites through a landco that leases the sites to the developer.

For developers who already own — or are in a position to acquire — sites for future projects, the landco opportunity has further dimensions.

By introducing a landco into its structure, the developer gives itself the option to raise capital against the project and site in unrelated transactions. The developer can retain the project company but sell the landco, or vice versa, or retain and finance both in separate transactions with unrelated counterparties.

For example, the developer could approach one of the real estate investment trusts or other active landco investors with an offer to sell the site.

Alternatively, a developer could borrow against a portfolio of landcos to pay other costs. For example, the landcos can be used as collateral to secure the obligation to prepay letters of credit that the developer must post to satisfy obligations to utilities under power purchase agreement or to grid operators for interconnection while projects are still in the development stage. Project finance banks have an incentive to provide letters of credit. It is a way to enhance their relationships with the developer while also giving the banks visibility into the developer's future project financing needs.

Holding a project and the project site in separate entities increases the aggregate economic value of both assets. The developer creates a rent stream that is effectively "preferred" project revenue, while eliminating the risk that the project site will be foreclosed on after the project is financed.

The developer has broad flexibility to select, via the rent payment terms, how much project company value will be allocated to the landco and thus what value the "preferred" project revenue stream will have.

The rent can be fixed in amount, such as a flat amount per acre or it can have variable elements, such as being tied partly to project gross receipts.

Whether it is fixed or variable, the rent can remain constant throughout the lease term, or it can include pre-set or contingent escalators. It can start high and ratchet down after a lessor rate of return is achieved. It can start low and ratchet up after a project company return is reached.

The rent can be structured as a fixed-income stream uncorrelated with project performance or it can be structure to approximate project equity-like returns, or any desired point in between.

The market is just starting to focus on the opportunities in rent design. Investors are starting to look beyond fixed rent streams in search of investments offering a balance of risk and reward that eliminates competition from bank lenders and justifies the returns the investors seek.

Developers also see opportunities. For example, a developer planning to sell a project, but wishing to retain a small stake in the equity returns, could create a landco rent payment stream that approximates equity-like returns, which the developer would continue to collect after the project is sold.

Developers are putting project sites into separate "landcos."

Bundled Transactions

The landco structure does not prevent a developer from deciding later to finance or sell both the project and the landco in a single transaction.

In circumstances where the land is already owned by a landco and it is undesirable to transfer ownership of the land to the project company, a bundled financing can be done by putting the project company and landco under a single holding company and having that holding company act as the borrower under the financing. The project company and landco would provide subsidiary guarantees of the debt.

Where that structure is used to finance a renewable energy project, the presence of a landco has been shown to increase, modestly, the amount of debt that the project can support.

Debt in the typical renewable energy deal is back-levered. A tax equity investor co-owns the project company with the developer, and the lender lends against the cash distributions that the developer expects to receive over time. Typically, the financed cash distributions consist solely of amounts payable to the developer on account of its ownership interest in the tax equity partnership. The landco structure creates a second source of distributions, re-routing project revenues (in the amount of rent) from the project company to the landco, and from landco to the developer. Developers have successfully argued that the re-routed cash is more likely to be received by the developer and, thus, the developer should be permitted to borrow more, on a proportionate basis, against such cash.

Put another way, developers financing renewable energy projects and project sites in bundled transactions have been able to increase, modestly, the amount of back-levered debt that can be borrowed by running part of the cash that will be used to repay the debt through a landco.

Impact on Financeability

Developers often ask how a landco structure will affect the financing of a project company on a standalone basis, meaning unbundled from the landco.

The primary impact is a reduction in the amount of debt the project company can borrow. Cash is being diverted from the project company to the landco to pay rent. This reduces the cash that the project has to borrow against.

There are ways to mitigate the impact. For example, rent payments could be structured so that they decrease during periods when the project company is at risk of failing its debt-service-coverage-ratio test, with / *continued page 32*

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CFIUS said in its latest annual report to Congress at the end of July that is now takes an average of 45 business days to review proposed acquisitions of US companies by foreign investors.

It takes an average of another 86 business days if the transaction moves into an investigation phase.

The latest report covers calendar year 2020.

The likelihood that an acquisition would be rejected increased significantly during the Trump years.

Chinese companies were still investing in US companies during 2020. However, Chinese filings were down compared to past years. Only 17 filings were made by Chinese companies in 2020 — 20 if Hong Kong is counted — compared to 55 in 2018 and 25 in 2019.

CFIUS stands for the Committee on Foreign Investment in the United States, an inter-agency committee of 16 federal agencies, headed by the Treasury Department, that reviews potential foreign acquisitions for national security implications. The committee reports annually to Congress.

Filing of transactions with CFIUS used to be voluntary. Filings are made only in a fraction of acquisitions. The danger of not filing is that the government could force the transaction to be unwound later if it has national security concerns. However, some filings are now mandatory after a recent change in the statute. (For more detail, see "Scrutiny For Inbound US Investments" in the October 2019 *NewsWire* and "Expanded Reviews of US Inbound Investments" in the February 2020 *NewsWire*.)

Most transactions that raise problems are voluntarily withdrawn. Many are later resubmitted on revised terms. In some cases, transactions are approved after the acquirer agrees to mitigation measures.

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Landcos

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catch-up payments later. If the rent amount is tied to project performance, such adjustments are automatic.

As a secondary impact, if the land is not owned by the project company, it opens a discussion with the lenders as to whether the land acquisition costs should be counted as funded equity, or “skin in the game,” for purposes of calculating the project’s debt-to-equity ratio.

Landco arrangements typically have a negligible impact on tax equity financings. In most current tax equity partnership structures, most of the cash generated by the project is distributed to the developer. Thus, while project revenue projections affect the amount of tax equity that can be raised, reduced revenue projections typically have a modest impact on the tax equity investment.

Care must be taken to avoid making rents a share of net income earned by the project company. That could cause the landco to be considered a partner in a larger partnership with the developer and tax equity investor.

In cases where an investment tax credit will be claimed on a project, there may be a benefit to keeping items like land, that do not qualify for the investment credit, out of the project company so as to allow the tax equity investor to claim an investment credit on a larger percentage of its investment.

Developers considering rent payments linked to project performance for projects on which an investment tax credit will be claimed should ask the appraiser what effect the rent stream will have on project valuation. If it reduces the valuation, then the amount of tax equity that can be raised will also shrink.

Finally, section 467 of the US tax code limits the extent to which rent can fluctuate in a lease. The section 467 tax consequences may have an effect on project economics.

Lease Terms

Lenders and investors will want to ensure that the landco structure does not create exposure to any unusual or off-market risks.

A developer negotiating a lease between a project company and an affiliated landco should look consider the lease terms from the perspectives of both future lenders and investors. Future counterparties may feel compelled to take a particularly close look at the lease terms given that they were “negotiated” between affiliated companies.

Site leases used in precedent transactions may not be suitable, especially from the lessor perspective. While sites leases of financed projects have usually been vetted by sophisticated counsel to ensure adequate protection for the project owner, they may not have been reviewed as rigorously on behalf of the site lessor. Even if they were, it is unlikely that the precedent lessor sought the full scope of rights and protections that a developer would need to maximize the value of its landco.

Where possible, developers planning to finance or sell projects and sites separately should ask both sets of counterparties to sign off on the form of site lease before closing either transaction, since the developer’s ability to address unanticipated counterparty comments through edits to the site lease will be significantly constrained after the initial closing. ◎

University Energy Partnerships

by Jake Falk, in Washington

Universities across the United States are looking for private companies to modernize, operate and maintain university energy and utility systems.

A wave of deals has closed in the last few years, including partnerships for energy and utility systems at The Ohio State University, the University of Iowa, Syracuse University, the University of California at Fresno, the University of Idaho, Georgetown University and Howard University.

More deals are in procurement or are in planning and are expected to be procured in the near term.

The transactions are structured as long-term leases of university utility systems or concessions to provide utility services and require the private company providing the utility services to meet key performance indicators, or KPIs, in exchange for payments from the university during the term of the agreement.

A number of deals have been public-private partnerships, or P3s, where a public university enters into a partnership agreement with a private company, but private universities have also closed deals.

Motivations

The reasons for entering into these arrangements vary from university to university, but certain common objectives have emerged.

Universities want to modernize or replace aging university utility systems, including central utility plants and steam facilities. They are interested in increasing the sustainability and resiliency of university utility systems and achieving other environmental, climate or energy objectives.

Some are looking to drive better utility system performance and increase the efficiency and reliability of their utility systems.

Some want to leverage physical capital to gain access to funding for utility-related projects and for other strategic investments.

Another motivation is to lock in predictable, long-term and sometimes reduced payments for campus energy and address deferred maintenance issues.

These arrangements can also better / continued page 36

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The committee makes recommendations. The president has ultimate authority to block a transaction. Presidential action to block a transaction is rare.

The number of mandatory filings increased dramatically during the period 2018 through 2020. These filings are made on short-form declarations.

They are required in two situations.

One is where a foreign government acquires a substantial interest in a US company that handles critical technologies, critical infrastructure or sensitive data.

The other is where a foreigner acquires an interest in a business that makes critical technologies for use in any one of 27 specific industries. The industries include nuclear power generation and manufacturing transformers, turbines or batteries.

The number of mandatory filings was 20 in 2018, 94 in 2019 and 126 in 2020.

The largest single category of such filings in 2020 was for investments in US power companies. There were 13 such filings in 2020. The next largest category of mandatory filings was for companies engaged in computer design (11).

The top six sources of mandatory filings were by investors from Canada (20), Japan (18), the United Kingdom (12), Germany (10), Sweden (7) and China (6, counting one from Hong Kong).

No short-form declarations were rejected in 2020. It took CFIUS on average 30 business days to process such a declaration.

Full filings and investigations of proposed deals spiked during the first two years of the Trump administration and then fell in 2019 and 2020, approaching a more normal pattern. A full filing is most likely to be made in cases where a foreign company is investing in a project near a US military base or other sensitive government installation.

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University Partnerships

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align university resources with teaching, research and the core university mission of education, by delegating utility system responsibilities to third parties with operational expertise.

Deal Structures

Notwithstanding these common goals, different deal structures have emerged that reflect the different needs and objectives of the universities involved in these deals.

One common deal structure focuses on the long-term operation, maintenance and optimization of an existing utility system. This deal structure typically requires the private company to make a substantial upfront payment (which has exceeded $1 billion in some of the largest deals) in exchange for the rights to the concession or lease. The university, in turn, is required to pay utility fees over the term of the agreement. The utility fee structure usually includes payment of some or all of the following amounts: a fixed-fee component, an operation and maintenance component that may be capped based on historic O&M costs and expected future O&M performance, and variable components that provide a return both of and on capital investments made by the private company.

In this deal structure, the university usually wants to maintain some control, including approval rights, over the capital improvements that will be made on the university campus during the term of the agreement. At the same time, the private company will want assurances that it will be able to make the capital improvements that it is required to make during the term, including in order to comply with applicable laws and KPIs.

The private company may also be assuming a certain level of capital investment and return in its base case projections. It may want assurances that it will have the opportunity to make this level of capital investment during the term.

Another deal structure provides for the upfront modernization or replacement of an existing, aging or run-down utility system, as opposed to capital improvements during the term.

In this structure, there may not be an upfront payment by the private company. It will be responsible instead for financing construction of the new facilities. The university repays the financing over the term of the agreement. Given the front-loaded construction period, this structure may not involve as long a term and the payment mechanism may not assume major capital investments during the term, beyond maintenance of the initially-installed infrastructure.

The rest of this article is a high-level survey of the first wave of deals that closed, the deals that are currently in procurement or under negotiation, and certain deals that are in planning and that may come to market in the near term.

First Wave

Ohio State University:

The Ohio State P3 was the first university energy partnership of its kind to close in the United States, and it set the precedent for some of the ensuing deals.

The deal closed in 2017. The private company, Ohio State Energy Partners, is a joint venture between ENGIE North America and Axium Infrastructure. The joint venture was awarded a 50-year lease to operate and maintain the university's power, heating and cooling systems. It will be responsible for energy conservation measures to help the university meet sustainability objectives, including to improve energy efficiency by 25% within 10 years, and other

A wave of deals has closed recently where universities turn over campus utility systems to private companies.

system improvements to be made during the 50-year term.

The joint venture paid the university $1.015 billion at closing, and it has agreed to pay another $150 million toward an academic collaboration program. The university is paying the joint venture an annual utility fee that is comprised of a fixed fee (starting at $45 million), an operating fee that is aligned with operating costs (starting at $9.2 million) and a financial return for capital investments made by the joint venture (which is calculated based on an assumed 50% equity contribution at an initial return of 9.35% and an assumed 50% debt-financed contribution at an initial interest rate of 3.691%). The university will buy other electricity, natural gas and supplies it consumes directly from other providers during the term.

University of Iowa:

The Iowa P3 is similar to the Ohio State P3, but was structured to meet the specific objectives of the University of Iowa, including transitioning the university away from the use of coal and toward a zero-carbon footprint.

The Iowa deal was executed in December 2019 and reached financial close in March 2020. The private counterparty, Hawkeye Energy Collaborative, is a consortium comprised of ENGIE, Meridiam and Hannon Armstrong. Hawkeye Energy Collaborative will manage and operate the university's steam, cooling, water and electricity systems during the 50-year term of the agreement.

The deal will allow the university to meet its goals of being coal-free by January 1, 2025 or sooner and to explore opportunities to buy renewable fuels and incorporate sustainable, lower-cost fuel options into the existing utility systems.

The university received an upfront payment of $1.165 billion from the consortium that it put into an endowment to be used to fund institutional priorities.

The deal will allow the university to invest $15 million annually toward the its strategic plan and core missions of teaching, research and scholarship.

The utility fee structure for the payments the university will make to the private consortium is similar to the utility fee structure for the Ohio State deal, including an annual fee of $35 million for providing the utility services.

University of Idaho:

The University of Idaho is using the same agreement structure as Ohio State and Iowa.

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Still, the odds of having a deal rejected was significant during all four Trump years.

There were 187 full filings in 2020. Eighty eight moved past review to an investigation phase. One deal was rejected during the initial review. Another 28 were withdrawn during or after the investigation.

During the last six years of the Obama administration — 2011 through 2016 – roughly 42% of filings led to investigations. The figure jumped to 72% in the first year of the Trump administration in 2017. It was 69% in 2018, 49% in 2019 and 47% in 2020.

The likelihood that a deal would be withdrawn also increased during the Trump years. It was 21% during the Obama years. It increased to 36% on average during Trump. These are percentages of deals that moved to an investigation phase. Withdrawn deals as a percentage of total filings were 8.9% under Obama and 21.7% — more than one in five — under Trump.

Six of the withdrawn deals in 2020 were refiled in 2021.

Of the full filings in 2020, 11% were in the power sector.

The top seven countries whose investors made long filings were China (20, including three from Hong Kong), Japan (19), the UK (14), France (11), and Australia, Sweden and Singapore (10 each).

CFIUS was tipped off by news reports or tips from federal agencies, the public or members of Congress in 117 cases during 2020 and asked the parties in 17 of the cases to file.

MOST INTERCONNECTION PAYMENTS and government grants to investor-owned water and sewer utilities will no longer have to be reported by the utilities as income if the bipartisan infrastructure bill that passed the Senate on August 10 is ultimately enacted.

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University Partnerships

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The Idaho deal was executed in November 2020 and reached financial close in December 2020. The private counterparty for the Idaho deal, Sacyr Plenary Utility Partners Idaho LLC, is a joint venture of Sacyr and Plenary. The joint venture will lease and operate the university's district heating and cooling, water distribution and electricity distribution systems during the 50-year term of the agreement.

The deal will help the university meet its goals of modernizing its utility systems, achieving institutional energy independence by having a micro grid on campus and incorporating energy conservation measures.

The university received an upfront payment of $225 million from the joint venture that will be invested with the university foundation and provide approximately $6 million annually to fund strategic initiatives.

The utility fees it will pay the joint venture are similar in structure to the fee structure for the Ohio State and Iowa P3s.

UC at Fresno:

The Fresno State P3 reached financial close on February 26, 2021 and involves replacing aging central utility infrastructure on the university campus.

The private counterparty is Bulldog Infrastructure Group, which is a joint venture of Meridiam and NORESCO.

The joint venture was awarded a 33-year concession to modernize and maintain the central utility infrastructure system that will require replacing a central utility plant originally built in 1954 with a new utility plant. The joint venture will also address the hot-water and chilled-water generation and distribution piping network, install solar panels over existing campus parking lots and take energy conservation measures within buildings to reduce campus energy usage and the carbon footprint.

The arrangement includes energy savings targets, with more than 30% of energy savings expected in the first year of operation, according to a press release from Meridiam. The joint venture financed its initial capital investment with a "sustainable development goals" impact bond whose interest rate is linked to the targeted 30% reduction in energy consumption. The interest rate incorporates financial penalties through the project life if energy performance objectives are not continuously met.

Syracuse:

Syracuse University was the first private university to enter into a similar long-term agreement for operation of its steam and utility systems. The Syracuse deal closed in September 2020. The counterparty in the deal is CenTrio Energy (formerly Enwave Energy USA).

A key element of the Syracuse deal is modernization of the university's steam station, which has been operating for nearly six decades and requires significant repairs and efficiency upgrades. The steam station operates around the clock every day of the year and serves other customers in addition to the university, including the State University of New York (SUNY) College of Environmental Science and Forestry, SUNY Upstate Medical

The private company makes a substantial upfront payment in exchange for fees over 50 years.

University, Syracuse VA Medical Center and the Crouse Irving Memorial Hospital.

Georgetown:
Georgetown University, another private university, reached an agreement with ENGIE North America to enhance, operate and maintain its electrical, heating, cooling and domestic water systems.

The deal, announced in early April 2021, is expected to help Georgetown meet its sustainability commitment by reducing energy consumption. ENGIE will be responsible for significant upgrades to Georgetown's major utility, distribution, monitoring and control systems.

The university said in a press release that it "could see a reduction of at least 35% in its energy use intensity — energy per square foot per year — by the end of the decade" and "the partnership will help Georgetown achieve its sustainability goals of becoming carbon neutral and water positive by 2030 and achieving '100% renewable power' by 2035."

Howard:
ENGIE secured a similar role at Howard University, where it will design, construct, operate and maintain a new central utility plant on the university campus.

Active Deals

University of Maryland:
The university issued a request for proposals to a shortlist of five teams competing for its NextGen Energy Program P3 to replace its aging energy and utility system.

The shortlisted teams responded to an earlier request for qualifications issued in April 2020.

The final RFP is expected later this year and a preferred consortium is expected to be chosen in 2022. The university expects the negotiated arrangement to have a 30-year term, but the term could be anywhere from 20 to 50 years, depending on the proposals the university receives.

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Water and sewer utilities will have different rules than electric utilities.

Electric utilities usually do not have to report interconnection payments from independent generators to reimburse for the cost of upgrades that must be made to the grid to accommodate a new interconnecting power plant. Such payments usually do not have to be reported as income by the utility as long as the independent generator is not also a customer of the utility. It would be a customer, for example, if it pays the utility to wheel its electricity across the power grid to a distant electricity purchaser.

In cases where the utility must report a payment as income, it charges a tax gross up that increases the cost to connect a project to the grid. (For more detail, see "IRS Updates Tax Treatment of Interconnection Payments" in the August 2016 *NewsWire*.)

Electric utilities must report most government grants as income.

The US has a problem with lead in water pipes. The utilities may need government grants to help pay the cost to replace such pipes.

The Senate infrastructure bill would spare investor-owned regulated utilities that provide water and sewage disposal from having to report amounts received to pay for equipment used to provide such services. This tax treatment would apply to cost reimbursements from private parties as well as government grants. The utility would have to spend the money on improvements by the end of the second tax year after the year in which the money is received.

The utility could not put the improvements into rate base.

The relief would only apply to utilities that are treated as corporations for federal income tax purposes.

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University Partnerships

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Louisiana State University:

LSU recently agreed to award a 30-year contract for modernization of its energy plants, distribution systems and building mechanical systems on its Baton Rouge campus to a team of CenTrio Energy and LA Energy Partners. CenTrio Energy is expected to finance the initial energy plant and distribution system improvements and certain other improvements during the term and be responsible for operation and maintenance. LA Energy Partners, a joint venture between Bernhard LLC and Johnson Controls Inc., is expected to design and build the initial improvements and future building mechanical systems improvements.

LSU said the arrangement is "projected to save LSU and the State of Louisiana approximately $90 million over the next 30 years." The agreement is also expected to address $22 million of deferred maintenance annually.

Future Deals

At least six universities around the country are planning or considering similar arrangements.

The University of Louisville is expected to release a request for qualifications for a 40-year lease of its utility system later this year.

Iowa State University earlier this year solicited advisors to assist with a potential utility system P3 for the Ames campus. The board of regents approved a similar P3 for the University of Iowa in 2020.

The University of Florida has hired advisors for a potential utility system P3 to replace an aging co-generation plant and other utility infrastructure serving the Gainesville campus.

The University of California at Berkeley is considering a P3, among other options, to replace a 30-year-old co-generation plant that produces steam and electricity with a new clean energy system.

The University of Washington asked potential bidders for expressions of interest in replacing its aging power plant and distribution system at its Seattle campus.

Finally, the University of Virginia is studying whether to expand its existing Massie Road power plant and whether to use private funding or other innovative delivery options for the project. ◎

Environmental Update

Here are the key takeaways from the latest comprehensive climate update that the United Nations Intergovernmental Panel on Climate Change — called the IPCC — released in early August. The new report distils 14,000 individual studies and has more than 200 authors.

The last decade was hotter than any decade in 125,000 years.

Atmospheric carbon dioxide is now at a two-million-year peak.

Greenhouse gas emissions have elevated the global average temperature by about 1.1° Celsius above the pre-industrial late 19th century average. Mankind has already emitted enough greenhouse gases to heat the planet by 1.5°C, but fine-particle pollution is providing a cooling effect.

The last decade was hotter than any decade in 125,000 years.

Scientists can now link specific weather events to human-made climate change. While it was previously impossible to attribute any particular storm or temperature spike to climate change, climate science has advanced since the IPCC's last update in 2013.

Drawing from research on ancient climates and using satellite technology, new models have narrowed the projections of the atmosphere's likely response to industrial emissions and provide a clearer picture of what may result if greenhouse gas emissions are not curbed.

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Some version of the infrastructure bill in which this provision is included is expected to be taken up in the House in the fall, but probably not before late October.

The provision applies to amounts received after calendar year 2020.

— contributed by Keith Martin in Washington

Environmental Update

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New findings rule out the possibility that unrestricted emissions will have only a mild effect on global temperatures.

Evidence suggests that the cessation of carbon dioxide and other greenhouse gases would reduce heating quickly and allow temperatures to stabilize within a few decades. Some effects will remain irreversible for centuries, including a sea-level rise.

In terms potential impacts on US regulation of greenhouse gases, the IPCC report is expected to form part of the scientific basis for National Environmental Policy Act regulations, inform oil and gas leasing decisions, and possibly accelerate efforts to calculate the social cost of greenhouse gas emissions. Environmental groups can also be expected to use the IPCC report to support climate liability lawsuits against fossil-fuel companies.

Cars and Trucks

President Joseph Biden announced a multipronged plan in early August to make cars and light trucks sold in the United States more fuel-efficient and to shift the US toward electric vehicles.

New regulations proposed by the US Environmental Protection Agency and Department of Transportation would require fleet-wide vehicle mileage of 52 miles per gallon by 2026, up from 40 mpg in 2021.

Biden also signed an executive order calling for half of new passenger car sales to be of electric "zero-emission" vehicles powered by batteries and fuel cells or plug-in electric hybrids by 2030.

Falling battery prices mean that larger electric cars will reach price parity with their fossil-fuel counterparts in the US and Europe in 2022, with parity reached in most other segments and regions by 2030. Improvements in battery technology are also expected to boost potential driving ranges.

The administration also called again on Congress to enact incentives to produce zero-emission vehicles and deploy public fast-charging stations.

Executives from various major automotive companies, lawmakers and United Auto Workers members joined Biden at the White House for the announcement.

The rulemaking reverses the freeze on fuel-efficiency standards imposed under Donald Trump, who eased requirements put in place in 2012 under the Obama administration.

Atmospheric carbon dioxide is now at a two-million-year peak.

Cross-State Air Pollution

A group of Midwestern utilities has expanded its legal challenges to an EPA cross-state air pollution rule that limits upwind discharges of ozone air pollution that arguably cause downwind states to flunk standards under the Clean Air Act.

The updated EPA rule became effective on June 29, 2021. It tightens national ambient air quality standards under the Clean Air Act for ozone.

It also requires power plants in 12 "upwind" states to reduce emissions of nitrogen oxides significantly starting in the 2021 ozone season.

States must reach a 2008 ozone national ambient air quality standard of 75 parts per billion.

EPA found that nitrogen oxides emissions in Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia and West Virginia significantly contribute to downwind states' nonattainment and maintenance problems for the 2008 ozone air quality standards under the Clean Air Act.

EPA is issuing new or amended federal implementation plans, or FIPs, in those 12 states that set tighter emissions budgets for power plants. Power plants in eastern states are already allowed to trade emissions allowances as a market mechanism to limit emissions.

A "good neighbor" provision in the Clean Air Act requires states to mitigate their "significant contribution" to the problems of other states in attaining and maintaining compliance with established ambient air quality standards.

Regulators use computer modeling to predict whether states will be in nonattainment with the standards and screen for significant contribution by upwind states to the ozone levels of downwind receptors. EPA then applies a test for cost-effectiveness to decide what emissions reduction measures are required of upwind states.

The litigation brought by a group of utilities and factories calling itself the Midwest Ozone Group says the methodology behind EPA's updated rule is faulty. The group argues that EPA failed to show a sufficient link between emissions in upwind states and resulting ozone problems in downwind states and challenges the standard EPA uses for determining such a link.

The group also says that EPA wrongly targets power plants rather than other emissions sources and requires steps that are not cost effective.

The lawsuit also challenges EPA's threshold for determining "significant contribution" by upwind states to the ozone levels of downwind receptors.

The case is *Midwest Ozone Group v. EPA* and is before a US appeals court in Washington.

Air Toxics Rule

EPA submitted proposed revisions to the mercury and air toxics standards — called MATS — for power plants to the White House Office of Management and Budget in early August for regulatory review. This is usually the last step before making them public.

The proposal revises a Trump administration May 22, 2020 rule on MATS.

Specifically, EPA appears likely to eliminate a decision made during the Trump era that it is not "appropriate and necessary" to regulate utility air toxics under section 112 of the Clean Air Act. The Trump EPA found that the agency's prior conclusion that it was "appropriate and necessary" to be incorrect. By removing the finding, the Trump administration removed a legal prerequisite to regulation under section 112. EPA is now expected to reinstate the finding.

The new rulemaking also appears likely to tighten emissions limits. Under a required risk and technology review, EPA must evaluate health risks and assess whether new, cost-effective control technologies are available. Depending on its findings, EPA can tighten mercury and air toxics emissions limits.

The OMB review process could take about 90 days, but comments by Acting EPA air chief Joe Goffman suggest the OMB review is expected to be much quicker.

Greenhouse Gas Regulation

Industry and various Republican-led states are asking the US Supreme Court to review EPA's authority to regulate greenhouse gases under the Clean Air Act.

They want an immediate review by the high court of a January lower court ruling that set aside a narrow, Trump-era approach to power plant climate rules.

The Biden administration asked the high court to reject the petitions, arguing that it is premature for the court to explore the scope of EPA's authority to regulate carbon emissions from power plants until after the agency decides on a new direction.

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Environmental Update

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EPA says it will issue a new section 111(d) greenhouse gas rule for power plants "after taking into account all relevant considerations, including changes to the electricity sector that have occurred during the last several years."

The Biden administration argues courts should not "speculate" about the potential approach an agency will take to new regulation.

The lawsuits have been consolidated as *West Virginia v. EPA*.

The issue before the court is a longstanding dispute about whether EPA can ground section 111(d) greenhouse gas emissions targets on actions taken "beyond the fence" of regulated plants — for example, by setting up emissions trading schemes — or whether it is limited to requiring actions to reduce emissions at specific power plants.

— *contributed by Andrew Skroback in New York*

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