NORTON ROSE FULBRIGHT

PROJECT FINANCE
NewsWire
October 2022

Observations of a Departing ISO Board Member

by Barney Rush, in Washington

Editor's note: Barney Rush served for nine years, until September 30, on the board of ISO-New England and is a former CEO of Mirant Europe and of an early hydrogen producer, H2Gen. He spoke in August to the Northeast Public Power Association about two intersecting existential crises affecting the power sector. The following excerpts are from that talk.

Twin Crises

Naturally, one accumulates many thoughts over nine years. My comments today are my own personal thoughts, and I am not speaking as a representative of the ISO, its management or my fellow directors.

First let me honor your profession of serving in the public power sector.

Many of you may be familiar with the multi-volume biography of Lyndon Johnson, written (and still being written!) by Robert Caro. In the first volume, Caro uses a chapter to describe what the Texas hill country was like before electricity: the harsh and exhausting rigor of daily life. Men rising at 3 am to milk their cows by hand; women yoking themselves up to carry heavy pails of water up the hill to the home, then washing the heavy clothes by slapping them with paddles and ironing with hot coals in sheds that became furnaces in the heat. All this at a time, in the 1930s, when urban America had had electricity for */ continued page 2*

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WAGE AND APPRENTICE guidance is expected by year end.

The guidance will start a 59-day clock to run for developers of renewable energy, storage, hydrogen, biogas and carbon capture projects to start construction to qualify for exemption from wage and apprentice requirements in the Inflation Reduction Act.

Developers whose projects will not be under construction in time are putting language not only in construction contracts, but also in operations and maintenance agreements to require compliance.

The Inflation Reduction Act restored tax credits to the full rates for projects that use renewable energy to generate */ continued page 3*

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over two decades.

President Roosevelt had a vision that all Americans, regardless of income, regardless of how rural their life, deserved the comfort and the freedom from toil that electricity provided. And so, the New Deal created the Rural Electrification Administration, to bring electricity to those who were not being served by utilities.

The young congressman, Lyndon Johnson, lobbied hard to bring the funds to his district that allowed the wires to be strung. The lights went on across the Texas hill country in 1938. And that year, so reports Caro, parents across his district named their newborn sons, "Lyndon."

Serving the public, with low cost and reliable power: that is the heritage and core values of your profession.

I would also like to honor the ISO New England management team. I acknowledge that my own early background in viewing management was not very elevating: I worked at Lehman Brothers in the 1980s, where if one asked "How many Lehman Brothers partners does it take to screw in a light bulb?", the right answer was "Nine: One to screw in the light bulb and eight to push the ladder over."

But kidding aside, in my professional life, I have never worked with management as collegial or thoughtful, as determined to find workable solutions to the problems that must be faced, or as respectful and mindful of the views of others. It has been a privilege to work with them and with my colleagues on the board.

We as a nation face two existential crises: threats from climate change and the growth of authoritarianism.

Perhaps discussing these two together will surprise you. But New England must grapple with the impacts of both, and I would like to explore these two grave threats, and their intersection, on our power system and our customers.

Climate Change

I recall a New England Power Pool sector meeting in 2017, during which I asked the representatives from the transmission sector what keeps them up at night.

The answer: increasingly severe storms, and the consequent investment needed to upgrade distribution lines and maintain reliability. Of course, these concerns are only one facet of the overall problem, which includes severe heat, rising sea levels and drastic changes to the survival of plants and animals around the globe.

I have traveled my own journey on the imperative of dealing with climate change: from recognizing it as an issue, to taking it seriously, to regarding it as a matter of urgency.

But urgency must not obscure realism.

First, realism in respect of geography: The only solution is a world-wide solution. I recall listening to a government official of Rhode Island say that the people of his state really cared about climate change because of the looming danger of sea-level rise in Narragansett Bay.

I thought to myself — what possible difference can Rhode Island make on its own to the height of water in Narragansett Bay? — and that the Indian solar company that I chaired at the time, Azure Power, probably had greater scope for helping due to its efforts to decarbonize a rapidly-growing major country still dependent on large thermal coal plants.

Recognizing the need for climate change to be addressed on a global basis can breed cynicism. Why bother about our small piece of the planet, when it amounts to so little of the total that must be transformed? Yet clearly, decarbonizing New England remains our job. All

> Climate change and the growth of authoritarianism threaten our power system.

regions of our country must do their part, not only to clean our national economy, but to demonstrate by example.

No one should doubt how difficult it is for large emerging markets to decarbonize; yet we also know that whatever influence we may have on the policies of other nations, that influence is nil without the solid evidence of our own commitment.

Second, we must be realistic in terms of time.

I have no doubt that all of you know how daunting the challenge is. Most of the New England states have had policies in place for a decade to incent more renewable energy. Yet after this time, only about 10% of the power on our grid, along with rooftop solar, comes from these sources. And looking ahead, construction of New England's offshore wind projects — as major an effort as that is — is only one of many requirements: finding land for onshore wind and solar, the years ahead to develop technologies such as modular nuclear reactors and long-duration storage, and construction of thousands of miles of additional transmission lines.

The Future Grid Reliability Study, just released by the ISO at the end of July, puts these challenges into stark relief. New England currently has 5,600 megawatts of wind, solar and storage capacity. The deep decarbonization scenario will require between 73,000 and 90,000 megawatts of such capacity — 15 times as much as we have today.

To meet the vast increase in the demand for storage, the world must rapidly scale up production of such essential inputs as cobalt and rare-earth elements. The recent study on storage from MIT highlights this challenge: production of these elements will have to increase at sustained compounded annual growth rates that are two to four times what has been achieved in single years in the past.

We would all wish to find ways to speed up the transition. But we should also be aware that the faster the transition, the more it must rely on technology that is commercial today, especially wind and solar. It takes time to nurture new technologies such as small modular reactors that I hope will have great success. There is a limit to compressing the schedule of research and development, certification and testing. Some of my colleagues on the ISO board have made this point succinctly: "Nine women cannot make a baby in a month."

Such sobering thoughts do not dampen my optimism that we can substantially decarbonize our economy. But by when? By 2030, as some politicians have proclaimed? */ continued page 4*

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electricity, increased tax credits for carbon capture and authorized new tax credits for such things as standalone storage and clean hydrogen, plus authorized bonus credits for projects in "energy communities" or that use domestic content.

The changes came with fine print.

Mechanics and laborers employed directly by the developer or by construction contractors or subcontractors to work on a project not only during construction, but also on "alterations and repairs" for the next five to 12 years after the project is in service, must be paid the same "prevailing wages" that are paid on federal construction jobs. These wages must be paid for five years after the in-service date on projects on which investment tax credits are claimed and for the period that production tax credits are claimed on other projects.

The required wages vary by job type and location. They are published on the US Department of Labor website.

However, there are no postings for many job types or locations. The US Treasury will have to explain what to do in such cases. Examples are a drilling rig operator to drill a geothermal well or workers on the US outer continental shelf constructing offshore wind projects. Developers can file a form with the Department of Labor for a wage determination, but the department was already receiving more than 1,000 such requests a year before the Inflation Reduction Act.

Qualified apprentices must also be used for at least 10% to 15% of total labor hours. The percentage is 10% for projects on which construction starts in 2022, 12.5% for projects starting construction in 2023 and 15% thereafter. At least one qualified apprentice must be used on any job that at least four individuals will handle.

The qualified apprentice program dates from the Great Depression when President Franklin Roosevelt hoped to have unemployed people learn construction ***/ continued page 5***

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Clearly impossible. By 2050? That seems plausible and would be a stupendous achievement.

If the timeline I offer seems a low bar to some, let me note the danger of proclaiming targets that are patently unrealistic. For when such targets are not met, public officials lose credibility and hence the confidence of the citizens they lead, when, in fact, it is vital that officials retain the confidence of the public for a transition that is so challenging and costly.

We must also recognize that while pursuing this goal, reliability must be maintained, even as we greatly increase the amount of electricity we generate and do so with an increasing scale of intermittent resources, but let's be clear.

Local fervor can become collective hypocrisy if we proclaim the urgency of decarbonization while resisting the infrastructure needed to help.

The importance of maintaining reliability is not a counterweight to the need to decarbonize. To the contrary, maintaining reliability is the handmaiden of decarbonization, for if the public were ever to believe that we must choose between reliable supply of what our lives depend upon and a further decrement in carbon emissions, the public's support for the transition will plummet. Further, we will jeopardize the people's interest in decarbonizing two other sectors — transportation and home heating — that now emit more carbon than the power sector.

Therefore, let us focus on incenting zero-carbon resources and the means to store power from them and thereby reduce the use of fossil plants, but not criticize the presence and need for these fossil plants themselves.

Markets

To encourage this transformation, it is important to hold a healthy regard for market forces.

Think of what market forces have already achieved. I remember, when I was a power industry executive in the 1990s, that we believed a natural gas price of $10 an MMBtu was a given. But then came the massive growth in fracking that led to the price collapse, and this, in turn, propelled the massive switch from coal to gas-fired generation around the country, cutting carbon emissions per kilowatt hour in half at every new plant that replaced an old coal station.

We had come to believe that the era of low gas prices would endure, with resulting low marginal prices in our energy market. We have therefore been grappling with the issue of how key regional assets, such as our nuclear power plants, would remain profitable and serve our needs.

But suddenly, we now face a dramatic increase in natural gas prices. A war-induced blip?

We should recognize that perhaps the low prices we enjoyed were the result of both plentiful supply of fracked gas and the constraint on exporting LNG, suppressing demand. That demand constraint has now been relaxed, and I expect that sustained worldwide demand for LNG will induce the construction of more export terminals, and hence provide steady uplift to domestic pipeline gas prices.

No doubt this price increase will induce more gas production, but we may still have a new general equilibrium that leaves prices well above the levels of this past decade. And this factor alone will provide a powerful incentive for renewables and other non-fossil sources of power.

To put this in perspective, economists have long thought that a reasonable price on carbon, if one were to be established, would be approximately $40 a ton. This would cause power prices to increase approximately 1.5¢ a kilowatt hour if a modern combined-cycle plant were setting the marginal price.

Yet the increase in natural gas prices over the past 12 months — from $3 to $8 an MMBtu — raises energy prices by more than

3¢ a kilowatt hour — double the impact of the oft-cited carbon price figure.

In sum, we may be moving from an era of cheap gas — which incented a wave of investment in gas-fired generation that drove national carbon emissions down — to an era of more expensive gas that will incent further investment in zero-carbon resources across the country, and thereby propel another steep decline in carbon intensity.

This is not to suggest that subsidies, incentives and market design do not matter: these instruments of policy and tariff matter a great deal. Just that we should remain both humble and nimble in our work and remain aware of the larger forces at play.

ISO-New England has an ambitious program of additional market design reforms, all designed to incent the provision of power that is steadily cleaner, always reliable and responsive to consumer concerns regarding costs.

As hard as it will be to launch these programs, my greatest concern is not our ability to do so, but rather the frictions that may not allow supply to respond to the carefully considered price signals we send.

Here are some examples.

A market structure puts pressure on the owner of a gas-fired power plant to ensure that there is enough fuel for a cold winter to ensure reliability. How can the owner respond? Will the community and authorities permit the owner to build a distillate oil tank as a back-up source of fuel in the event the natural gas supply is constrained?

The great disadvantage of wind and solar is the vast amount of land required for utility-scale projects. A solar project with only a 20% capacity factor requires about six to seven acres per megawatt. The amount of additional solar capacity envisioned in the ISO-New England Future Grid Reliability Study would require over 100,000 acres of land, just for solar, between now and 2040. How much local opposition will there be for the land required for sizable arrays?

Large-scale expansion of renewable energy and accessing hydro power from Canada require significant additional transmission lines. Easy to permit and build? Hardly. We need look no further than the successful effort to stop the Northern Pass transmission line in New Hampshire and the successful effort so far to stop the New England Clean Energy Connect transmission line in a remote part of Maine.

Those who oppose such projects are no doubt sincere. Yet clearly we will not make the progress needed to decarbonize if significant projects are successfully stopped / *continued page 6*

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trades by working alongside experienced workers. It will be interesting to see how the requirement works during a period of labor shortages. Registered apprenticeship programs are run mainly by labor unions and require certification by the US Department of Labor.

Projects that are unable to find qualified apprentices are excused. An example is where a project does not get a response from a program within five business days after making a request.

Tom West, the deputy assistant Treasury secretary for tax policy, told an American Bar Association tax section meeting on October 14 that the wage and apprentice guidance will be out by year end.

Projects that are under construction within 59 days after the guidance is issued are exempted from the wage and apprentice requirements.

There have been two ways since 2009 to begin construction. One is by starting "physical work of a significant nature" at the project site or at a factory on equipment for the project. The other is by "incurring" at least 5% of the total project cost. Costs are not considered incurred until the customer takes delivery of equipment or services, with one exception. A payment before the deadline counts if the equipment or services are reasonably expected to be delivered within 3½ months after the payment. Delivery can be at the factory.

The tax equity market has become comfortable relying on physical work, but requires developers to represent the project was under construction in time, as opposed merely to representing facts on which the investor can draw its own conclusion in cases where construction started under the 5% test.

The need to start physical work will put pressure on customers to place binding purchase orders promptly with manufacturers who have capacity to launch physical work on components in the next three to four months.

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by local opponents saying, "Yes, I take climate change very seriously, but not this project, not here." And we will not have the reliability we need if fuel storage projects are successfully stopped by local opponents saying "Yes, I understand we need to keep the grid reliable, but not with any fossil fuel."

Local fervor can become collective hypocrisy. We will proclaim the urgency of decarbonization and the need to maintain reliability, but not construct the infrastructure and plants we need to achieve our goals. This, in my view, is a most urgent public discussion that we must have.

Authoritarianism

The world has experienced an upheaval in the past six months that compels comment. We face another existential crisis — very different from climate change — but just as ominous: the renewed rise of authoritarianism.

The contest between democracy and autocracy has long been noted. Let me quote from Alexis de Tocqueville, in his magisterial account, *Democracy in America*, written in 1835:

> There are at the present time two great nations in the world. I allude to the Russians and the Americans. Both of them have grown up unnoticed; and while the attention of mankind was directed elsewhere, they have suddenly placed themselves in the front rank of nations, and the world learned their existence and their greatness at almost the same time.
>
> The American struggles against the obstacles that nature opposes to him; the adversaries of the Russian are men. The former combats the wilderness . . . ; the latter, civilization with all its arms. The conquests of the American are therefore gained by the plowshare; those of the Russian by the sword. The American relies upon personal interest to accomplish his ends and gives free scope to the unguided strength and common sense of the people. The Russian centers all the authority of society in a single arm. The principal instrument of the former is freedom, of the latter, servitude. Their starting point is different, and their courses are not the same; yet each of them seems marked out by the will of Heaven to sway the destinies of half the globe.

I feel chills when I re-read this passage. I first read it in college, in the early 1970s, at the height of the cold war, and marveled at de Tocqueville's prescience. I reread it in the 1990s, when we thought we could feel safe that these words had lost their relevance. But now, I read them again, with horror and foreboding. Who would have believed that today, a major European power would unleash a brutal assault on a peaceful neighboring country?

But also, while we fervently hope that Ukraine will prevail, and many believe that Russia has lost its superpower status, we must also contend with the rise of China — not as a nation joining the ranks of developed market economies organized by the rule of law, but as a highly centralized autocracy, with state-directed enterprises and an omnipresent surveillance of its people that even George Orwell could not have imagined.

And finally, we must be aware of a creeping rise of authoritarian instincts even within democratic states — such as Hungary — but also, frighteningly, here in our own nation as well.

How does this existential threat affect our world of providing electric power? In three ways.

The first is the immediate crisis caused by Russia's invasion of Ukraine and Putin's decision sharply to curtail the supply of natural gas to Europe. This of course has led to the steep surge of LNG prices and heightened the risk of New England not being able to procure LNG supplies it may need this coming winter. At times last winter, we faced pipeline gas and LNG prices of over $20 an MMBtu,

We must avoid demonizing perceived opponents and thereby torquing the anger of the public.

resulting in electric prices of over $150 a megawatt hour. Europe is now paying $60 an MMBtu for LNG in the summertime. Could these be the prices that New England generators will have to pay this coming winter, and perhaps the next, in competition for cargoes that will otherwise go to Rotterdam?

If faced with such prices for natural gas, the ISO markets will react to clear generators with lower-cost fuels, primarily oil. This could well require state and local authorities to provide necessary waivers for these plants to produce higher levels of carbon emissions. I expect that as strongly as New England wants to reduce carbon emissions, residents will want officials to mitigate such material price increases in any way possible. It will be vital that every oil- and dual-fueled unit on our system be well maintained and ready for this winter. The additional 1,200 megawatts of Canadian hydroelectricity under discussion would also substantially reduce the region's reliance on LNG, mitigating price spikes and enhancing reliability.

Beyond the impact of the upcoming winter, we can expect that the Ukrainian war will cause a seismic shift in the perspective and policies of western Europe. Russia will not be trusted for a generation or more, and governments will be determined to free themselves from being held hostage to Russian oil and gas. We can therefore expect even greater determination in Europe to advance towards a zero-carbon economy, driven now by a national security imperative, as well as climate change.

Europe's greater push will also heighten the near- and medium-term competition for the inputs to a clean economy and hence, at least initially, could affect the pace of transition that we wish to undertake in New England. There will be added pressure on all to resolve supply-chain bottlenecks.

The second impact of authoritarian government is associated with China.

China today manufactures 70% of the world's solar panels and, as importantly, is the leader in solar research and development. China mines 90% of the world output of rare-earth elements, so vital to decarbonization technology. With the values and attitudes that the Chinese leadership espouse, with the geopolitical threats that are emerging, can we be comfortable pursuing a fast-track commitment to decarbonization, based on such a supply chain?

Other nations have already begun taking defensive steps. The Indian solar market is burgeoning with virtually all the panels imported from China. Therefore, the Indian government, starting three years ago, began to impose what has become a highly dirigiste industrial policy that requires Indian / continued page 8

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The IRS generally requires construction of the entire project to be completed within four years after the year construction starts. The industry is pressing for seven years. Projects on federal and Indian land and offshore wind projects have 10 years.

The Treasury could adopt a different standard for starting construction to qualify for exemption from the wage and apprentice requirements. However, any change in the existing tests would not be well received by renewable energy developers.

SOLAR DEVELOPERS planning to import solar panels by mid-2024 to avoid any US anti-circumvention duties the US decides to impose on panels from Vietnam, Malaysia, Thailand or Cambodia must actually use the panels in projects by December 3, 2024, the Commerce Department said.

The Commerce Department released details of a two-year moratorium on anti-circumvention duties on September 15.

Formal imposition of the moratorium is a legal milestone that could lead to a suit by Auxin Solar and other US panel manufacturers to block enforcement.

The Biden administration is using authority under the Tariff Act of 1930 to suspend duties on "food, clothing, and medical, surgical and other supplies for use in emergency relief work."

Commerce responded, while releasing moratorium details, to complaints that the 1930 authority is not broad enough to suspend duties on solar equipment. It said that President Truman invoked the same authority in 1946 to suspend duties on timber, lumber and other construction materials to deal with a housing shortage as millions of soldiers returned home after World War II.

The moratorium will apply to collection of anti-circumvention duties on cells and modules imported through June 5, 2024.

The imported equipment must be used in projects by December 3, / continued page 9

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solar developers to purchase from domestic manufacturers.

Such considerations have now come to our shores, as evidenced by both the CHIPS Act to promote domestic manufacturing of semiconductors and the Inflation Reduction Act in which tax credits for electric vehicles are tied to batteries with high percentages of content from the US and other countries deemed safe and in which tax credits are also offered to spur manufacturing of solar panels in the US.

What more must we do to permit unfettered progress towards decarbonization?

Substantially reducing reliance on China will be costly and time consuming, and is likely to slow, at least initially, the speed of our transition. But we cannot allow China to do to us some day what Russia is doing now to western Europe.

Finally, we must look at our own nation. How do we combat our own authoritarian instincts? How do we abate the anger so many feel towards government? How do we reduce the despair that many feel at our seeming inability to solve major problems?

An important part of the answer can again be found in de Tocqueville:

> The strength of free nations resides in the township. Town institutions are to freedom what primary schools are to knowledge: they bring it within people's reach and give [people] the enjoyment and habit of using it for peaceful ends. Without town institutions a nation can establish a free government but has not the spirit of freedom itself . . . . In America, not only do institutions belong to the community but they are kept alive and supported by a community spirit.

Let me enlarge the scope of de Tocqueville's meaning: How do we behave as individuals, working within the local and regional institutions that we touch every day. Do we strengthen those institutions or weaken them? Do we advance democracy or abet its retreat?

What is required of all of us is civility, transparency, tolerance and a commitment to deal with facts.

We must avoid demonizing one's perceived opponent and thereby torquing the anger of the public.

Instead, we need to explain the issues that we are all working hard to resolve. With understanding, we can find common ground, make necessary compromises and forge solutions.

One of the major reasons it has been such a privilege to serve on the ISO board has been the opportunities to observe the high level of discourse among the stakeholders of our power system. But passions and perhaps COVID-induced separation have cracked our comity.

Our community can do better. With dialogue and understanding, we will have a far better chance of enhancing confidence in our institutions, strengthening our democracy, and building the broad, deep and enduring support for the policies of decarbonization that our region, our nation and our planet require. ◎

Hydrogen Tax Credits

by Keith Martin, in Washington

Companies angling to take advantage of new tax credits in the Inflation Reduction Act for making clean hydrogen are asking lots of questions.

Some of the questions will have to await guidance from the US Treasury.

The Treasury is expected to ask imminently for comments on the new hydrogen credits as a precursor to writing guidance.

A "clean hydrogen production standard" that the US Department of Energy proposed in early October answered at least one of the questions.

Two Options

The IRA gives anyone producing "clean hydrogen" the choice of production tax credits of up to $3 a kilogram for 10 years on the hydrogen produced or an investment tax credit of up to 30% of the cost of the electrolyzer and other equipment.

The investment tax credit is claimed entirely in the year the electrolyzer or other equipment is put in service. The hydrogen producer must choose between the two credits. It cannot claim both.

The credit amounts vary depending on the greenhouse gases emitted to produce a kilogram of hydrogen. The greenhouse gases are converted into CO2-equivalent emissions.

To claim credits at the full rate, the production process must lead to less than 0.45 kilograms of CO2-equivalent emissions per kilogram of hydrogen.

The following table shows the tax credit amounts where the CO2-equivalent emissions exceed that amount.

CO2e kilograms to produce a kilogram of hydrogen	PTC per kilogram	ITC
At least 0.45 but less than 1.5	$1.002	10.02%
At least 1.5 but less than 2.5	75¢	7.5%
At least 2.5 but less than 4	60¢	6%

No credits can be claimed on hydrogen produced with more than four kilograms of CO2 emissions per kilogram of hydrogen.

The CO2 emissions are measured on a lifecycle basis, meaning taking into account all of the emissions from feedstock through the point the hydrogen is produced / continued page 10

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2024. Commerce said the emergency does not justify waiving duties for solar companies to stockpile equipment they do not need immediately.

The moratorium applies to solar cells and panels made in the four Southeast Asian countries using Chinese parts.

It is retroactive to cells and modules imported earlier this year. Auxin petitioned the Commerce Department on February 8, 2022 to investigate whether Chinese panels were being routed through Southeast Asia to avoid high duties on direct imports from China. (For more details on the Commerce investigation and potential duties, see "Solar Tariff Moratorium and Customs Detentions" in the August 2022 *NewsWire*.)

The moratorium does not apply to Southeast Asian panels that use solar cells manufactured in China or Taiwan.

A preliminary decision is now not expected in the anti-circumvention investigation until November 28 after Auxin asked Commerce to delay an earlier August 29, 2022 deadline to allow presentation of more evidence.

TAX EQUITY PARTNERSHIPS take note.

The US Tax Court suggested that partners who do not agree to "deficit restoration obligations" should be allocated income annually to close any deficit capital accounts.

This could affect project developers who enter into tax equity partnerships and keep most of the cash, driving their capital accounts negative.

The US gives partners wide latitude to divide up returns from a partnership as they wish, but with one main constraint. The partnership must keep capital accounts for each partner and use them to distribute what asset value remains when the partnership liquidates. Capital accounts are a metric for tracking what each partner put in and took out of the partnership.

A partner's capital account increases as the partner suffers a / continued page 11

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(rather than also through consumer use). Hydrogen producers can petition the IRS to determine their lifecycle emissions rates.

The production tax credit amount will be adjusted annually for inflation using 2022 as the base year for measuring inflation.

Production tax credits can only be claimed on hydrogen produced in 2023 or later.

The hydrogen must be produced for sale or use as hydrogen, and the quantity sold or used must be verified by a third party.

The hydrogen must be produced in the United States or a US possession like Puerto Rico.

Production tax credits cannot be claimed on hydrogen produced at a facility that is owned by one company and used by another company. An example is where company A owns a plant and leases it to company B to be used to make hydrogen. The owner and user must be the same company for tax purposes. This is not a barrier to claiming an investment tax credit.

Hydrogen PTCs may be claimed for 10 years starting on the date the facility is originally placed in service. Thus, a facility put in service before 2023 will have used up part of the 10-year period by the time it is able to start claiming tax credits. However, a facility that was not producing clean hydrogen before 2023 and that is modified in 2023 or later to produce such hydrogen can treat the 10 years as starting when the improvements are placed in service.

Hydrogen producers will have the option to be paid the cash value of production tax credits — but not the investment tax credit, if that option is selected — under an IRS refund process, but only for the first five tax years of credits commencing with the tax year the producer places the hydrogen plant in service. The five-year period cannot stretch beyond 2032. Tax credits after the refund period ends can be sold to other companies for cash (as can investment tax credits). (For more details on transferring tax credits, see "Searching for Opportunities in the Inflation Reduction Act" in the August 2022 *NewsWire*.)

An investment tax credit cannot be claimed on a hydrogen plant put in service before 2023 or on tax basis built up before 2023 where the plant was already under development or construction before 2023.

However, it appears that one benefit of claiming an investment credit is the ability to claim bonus credits for hydrogen plants in "energy communities" or that use domestic content that could increase the hydrogen ITC to as high as 50%. (For more details, see "Searching for Opportunities in the Inflation Reduction Act" in the August 2022 *NewsWire*.)

Projects must be under construction by the end of 2032 to qualify for hydrogen tax credits.

The tax credits will be only a fifth of the full rate unless mechanics and laborers working on the project are paid at least "prevailing wages" as determined by the US Department of Labor and qualified apprentices are used for at least 10% (increasing to 15%) of total labor hours, both during construction and when making any repairs or alterations during the full period production tax credits are claimed or, where an investment tax credit is claimed, during the five-year period the ITC is subject to recapture. Apprentices are supposed to be used to train more workers for jobs in the green economy. (For more details, see "Wage and Apprentice Requirements" in the October 2022 *NewsWire*.)

The ability to claim hydrogen tax credits turns on the level of lifecycle greenhouse gas emissions.

The IRA allows owners of wind, solar and other renewable energy and nuclear power plants to use the electricity they generate in 2023 or later to make clean hydrogen and still claim separate PTCs on the electricity output, thus doubling up on PTCs for generating wind, solar, geothermal or nuclear electricity and then using the electricity to make green hydrogen. Normally, PTCs can only be claimed if the electricity is sold to an unrelated person.

However, care must be taken not to lose depreciation on the power plant. Tax losses cannot be claimed on property sold to an affiliate. Electricity is considered property for this purpose. Many renewable energy power plants have tax losses for the first three years on account of front-loaded depreciation. (For more details, see "Section 707(b): Related-Party Electricity Sales" in the June 2021 *NewsWire* and "Utility Tax Equity Partnerships" in the August 2021 *NewsWire*.)

Common Questions

Companies planning to make clean hydrogen are asking a number of questions.

One is whether tax credits can be "stacked," for example by claiming hydrogen PTCs or a hydrogen ITC, section 45Q credits for capturing the carbon emissions and section 45Z credits for making sustainable aviation or other clean transportation fuels. The answer is no if done at the same "facility." The Treasury will have to address what happens if the hydrogen plant and the carbon capture or fuel production equipment are owned by different parties.

Another frequent question is whether projects can buy renewable energy credits or enter into virtual power purchase agreements with renewable energy projects to offset emissions from using grid electricity.

Senator Tom Carper (D-Delaware) asked Senator Ron Wyden (D-Oregon), the floor manager for the Inflation Reduction Act tax provisions, that question shortly before the Senate vote in August. Carper asked whether the intention is to allow hydrogen producers to use "indirect accounting factors" such as RECs, renewable thermal credits, renewable identification numbers (RINs) and biogas credits to reduce effective greenhouse gas emissions. Wyden said yes.

There are rumors that any such ability to claim RECs as offsets may be limited to renewable energy projects in the same geographic area, possibly by balancing authority. There are 66 separate balancing authorities in the US.

The US Department of Energy issued a proposed clean hydrogen production standard, called "CHPS," for comment in October on which the IRS is likely to rely. One question the department asked is whether "renewable energy credits, power purchase agreements, or other market structures" */ continued page 12*

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detriment, like contributing more capital to the partnership or having to report a share of the income the partnership earned on the partner's tax return. It decreases as a partner receives a benefit, like being allocated tax losses or distributed cash.

The partnership cannot allow a partner's capital account to go negative unless the partner has agreed to contribute more capital, when the partnership liquidates, to close any capital account deficit. This is called a "deficit restoration obligation" or "DRO." (The IRS may ignore some DROs. For more detail, see "Deficit Restoration Obligations" in the December 2019 *NewsWire*.)

In cases where a partner does not agree to a DRO, then the partnership cannot continue allocating that partner tax losses once its capital account hits zero. Any remaining losses shift to the other partners.

The partnership agreement must also have a "qualified income offset" provision that says when a partner's capital account is driven negative by an unexpected adjustment, allocation or distribution, the partner must be allocated income as quickly as possible to eliminate the deficit.

An accounting firm in Redmond, Washington that was organized as a partnership dissolved in 2013 after two of the three partners withdrew to form a competing firm and took clients with them.

The partnership agreement had standard language requiring maintenance of capital accounts for the partners. The partners did not agree to DROs. The agreement had a qualified income offset provision that said if a partnership capital account was driven negative, the partnership would allocate income to the partner as quickly as possible to eliminate the deficit.

The partnership agreement had a two-year non-compete provision for withdrawing partners. It treated any partners who withdrew and whom clients ***/ continued page 13***

Hydrogen

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should be taken into account as potential emissions offsets and, if so, whether there should be "restrictions on time of generation, time of use, or regional considerations."

DOE said that CHPS is not a regulatory standard, but that it aligns with the hydrogen tax credits. The department has $8 billion in grant money to award to six to 10 hydrogen hubs. It said it may still select some projects that have higher emissions than the CHPS standard to qualify as clean hydrogen, but that still help reduce greenhouse gas emissions across the supply chain.

DOE is assessing whether any restrictions should be placed on counting RECs or virtual power contracts with wind or solar projects as emissions offsets.

DOE gave two examples of where it thinks projects would fall on the emissions spectrum.

It said that it expects electrolysis systems can limit lifecycle emissions to approximately four kilograms of CO2 equivalent per kilogram of hydrogen produced by limiting grid electricity to about 15% of total power used. It said a steam methane reformer that uses all grid electricity, with average US emissions for such electricity, should be able to do so as well by capturing and sequestering 95% of its carbon emissions and limiting upstream methane emissions to 1%.

Hydrogen producers have been asking whether tax credits can be claimed where hydrogen is produced as an intermediate chemical in a step toward producing a different end product. The Treasury will have to decide in guidance. One issue is how this differs from the case where hydrogen is produced and then converted into ammonia for transport where tax credits can be claimed.

DOE suggested in its CHPS standard that hydrogen produced as a byproduct of another process may qualify as clean hydrogen — for example, in chlor-alkali production and petrochemical cracking — but asked what companies normally do with such hydrogen and how much of the greenhouse gas emissions associated with the larger process should be allocated to the hydrogen.

Another frequent question is whether emissions from using grid electricity to liquefy or compress hydrogen for transportation must be taken into account as part of the lifecycle emissions. DOE said no. It said its CHPS uses the same lifecycle emissions boundary as used for the hydrogen tax credits.

The boundary includes "upstream processes (e.g., electricity generation, fugitive emissions), as well as downstream processes associated with ensuring that CO2 produced is safely and durably sequestered." Emissions associated with sequestration off site are taken into account. However, "other post-hydrogen production steps such as potential liquefaction, compression, dispensing into vehicles, etc." are not taken into account, DOE said. It said more than 20 countries are working to harmonize how their calculations are done.

Some types of fuels can have negative emissions. This would be true of things like municipal garbage and animal waste that would otherwise have been disposed of in ways that produce large greenhouse gas emissions if not used for hydrogen production. DOE asked for help figuring out how to quantify the negative emissions.

It also asked how emissions should be allocated among hydrogen and other co-products that are produced at the same time, such as steam, electricity, elemental carbon and oxygen. ◎

Bonus Tax Credits and the Inflation Reduction Act

by Keith Martin, in Washington

Three potential bonus tax credits in the Inflation Reduction Act could take investment tax credits on some projects as high as 70%.

Production tax credits could increase by as much as 20%.

The bonus credits only apply to projects placed in service in 2023 or later. Developers whose projects qualify have an incentive to delay completing year-end projects until early next year.

Some developers report difficulty persuading tax equity investors to accept that their projects qualify before the Treasury issues guidance to implement the bonus credits.

Energy Community

An extra 10% investment tax credit can be claimed on any project in an "energy community," assuming the project complies with, or is exempted from, wage and apprentice requirements. (For more detail, see "Wage and Apprentice Requirements" in the October 2022 *NewsWire*.) Otherwise, the additional investment tax credit is only 2%.

A project claiming production tax credits would multiply the base tax credit for which the project qualifies by 1.1.

A project in any of three locations qualifies.

One is a project on a "brownfield site," defined as "mine-scarred land" or a site whose use "may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant."

The site cannot already have been cleaned up.

Locations that have already been listed as Superfund cleanup sites, added or proposed to be added to the national priorities list, or are subject to a court or administrative order or consent decree requiring cleanup do not qualify.

Mine-scarred land includes not only a former mine, but also nearby waters and watersheds that were affected by processing of ore and other minerals.

Another location that qualifies as an energy community is any census tract where a coal mine closed after 1999 or a coal-fired generating "unit" retired after 2009 or a / continued page 14

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followed as receiving an in-kind distribution of an intangible asset — client goodwill — that belonged to the partnership. The value of the intangible asset reduced the partner's capital account.

The federal income tax return that the remaining partner filed for the partnership for 2013 showed the two withdrawing partners as having been distributed $742,569 in intangible assets attributable to clients who followed them to their new firm. This pushed their capital accounts negative. Therefore, the tax return allocated 2013 partnership income to close the deficits. The two withdrawing partners ended up being allocated larger shares of the 2013 income than they expected.

Each of them filed a Form 8082 with the IRS to flag that they were not filing their tax returns consistently with the income the partnership told them they had to report.

The IRS audited the partnership's 2013 return and took the side of the two withdrawing partners, arguing that the remaining partner should have reported a larger share of the 2013 income.

The US Tax Court largely disagreed with the IRS. The court said the qualified income offset provision that required partners who did not agree to DROs to be allocated income to close any capital account deficits was key.

However, it said the partnership should have first allocated among the three partners the amount that the intangible client goodwill had appreciated in value, thus pushing up their capital accounts. The partnership had a zero tax basis it.

Partnerships that dissolve and liquidate usually sell their assets and have income or loss from such sales to allocate that must be allocated to partners. In cases where partnership assets will be distributed to partners in kind, the partnership treats the assets as if sold and allocates the gain or loss inherent in the assets. This pushes up capital accounts before any liquidating / continued page 15

Bonus Tax Credits

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directly adjoining census tract.

The third location is any metropolitan or non-metropolitan statistical area that has currently, or had at any time after 2009, at least 0.17% direct employment or at least 25% local tax collections tied to extracting, processing, transport or storage of coal, oil or natural gas and that has an unemployment rate at or above the average national rate "for the previous year."

It is unclear to what year the phrase "for the previous year" refers. The Treasury will have to explain in guidance. However, developers have been getting comfortable with some locations by checking local unemployment rates against the national rate back multiple years and taking comfort if the local rate is consistently higher than the national rate.

Investment tax credits on some renewable energy installations could reach as high as 70%.

A bigger challenge is while the Office of Management and Budget publishes the statistical areas, it is hard at this stage to say definitively whether projects outside the obvious coal and oil & gas regions qualify. One issue is what to treat as the relevant area for projects in rural areas. It is unclear whether it is the single county where the project is located or also one or more neighboring counties. The Senate version of the Inflation Reduction Act had other language describing the third type of energy community as a placeholder until shortly before the Senate vote. The two Senate sponsors were given only 36 hours to reframe the provision. There was no time to consult with OMB about how best to describe the eligible areas.

The Bureau of Labor statistics keeps local employment data. BLS staff believe that 12 NAICS codes should be used to add up the amount of direct employment in coal, oil and natural gas. NAICS codes — for North American Industry Classification System — are used by the government to classify businesses.

It is proving a bigger challenge to determine local tax collections. Calls to local tax authorities and economic development agencies rarely turn up the information.

Companies have been asking what happens if part of the project is in an energy community — for example, where the project substation is on a brownfield site or a gen-tie line crosses a census tract where a coal-fired generating unit retired — or whether a temporary spike in employment to build gas-fired power plant or gas pipeline counts. The Joint Committee on Taxation staff said that employment with the local gas distribution company probably does not count. The Treasury will make the final call in guidance.

In the meantime, various groups, including the American Clean Power Association and the Solar Energy Industries Association, have published maps showing probable energy communities.

Domestic Content

An additional 10% investment tax credit can be claimed on projects that satisfy domestic content requirements. However, the additional tax credit is only 2% unless the project complies with, or is exempted from, the wage and apprentice requirements. Production tax credits on projects that qualify would be multiplied by 1.1 (or 1.2 if both the energy community and domestic content adders apply).

All iron and steel and at least 40% initially (increasing over time to 55%) of the cost of all manufactured products used to build the project would have to be produced in the United States.

The Inflation Reduction Act says to look to the Buy America regulations used for federally-funded transit projects for guidance.

Separate materials brought to the project site for incorporation into the project into two categories: construction materials and manufactured products.

Construction materials are materials that are made primarily of iron or steel. They must be entirely US made, meaning all of the manufacturing processes, but not mining of raw ore, must take place in the United States, except for metallurgical processes involving refinement of steel additives. Examples of construction materials are rebar, steel uprights and probably torque tubes that hold up solar arrays and offshore wind monopiles.

"Manufactured products" are products that are not primarily iron or steel.

Set up a fraction. The numerator is the cost of the manufactured products manufactured in the US. The denominator is the cost of all the manufactured products used to build the project. The fraction must be at least 40% for projects on which construction starts by the end of 2024, 45% for projects starting construction in 2025, 50% in 2026 and 55% thereafter. It starts at 20% for offshore wind projects, increasing to 55% for such projects that start construction in 2028 or later.

The federal transit regulations that are supposed to serve as a precedent distinguish among the end product, manufactured components and subcomponents. Manufactured components must be US made. It does not matter under the transit regulations where subcomponents are made.

This creates tension between local transit agencies and the federal government over what is the "end product." For example, the Metropolitan Transportation Authority in New York City said the end product for its construction of a new Second Avenue subway station was the subway station. However, the Federal Transit Administration treated the fire suppression system as a separate end product, with the result that pipes and valves for it could not be imported from Finland since they would be manufactured components rather than subcomponents if the end product is the fire suppression system rather than the entire subway station.

The Inflation Reduction Act treats the end product as the "facility," meaning a standalone battery or power plant.

The numerator of the manufactured products fraction is the cost of manufactured products that were manufactured in US factories. Mere final assembly in the US by welding together parts brought from overseas is not manufacturing. Manufacturing involves altering the form or function of the components by "adding value and transforming" the components into "a new product functionally different from that which would result from mere assembly."

"Cost" for this purpose should be the contract price paid by the customer rather than the cost to the manufacturer. Manufacturers are usually unwilling to disclose their actual costs.

Labor costs at the project site probably do not count. The aim of the manufactured products fraction */ continued page 16*

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distributions. It ensures that the sum of all the partner capital accounts will equal the remaining value inside the partnership.

The US Tax Court said the gain in the intangible client goodwill should have been allocated under the partnership agreement in the same ratio used for other income as if it had been realized before applying the qualified income offset provision to redirect enough income to partners with deficit capital accounts to close the deficits for the year.

It sent the parties back to recalculate the income allocations.

The case is *Clark Raymond & Company v. Commissioner*. The US Tax Court released the decision in mid-October.

A SHARED-APPRECIATION LOAN was a pure loan and did not make the lender a partner with the borrower, the US Tax Court said.

The lender also shared in net cash flow.

The US Tax Court said the borrower could deduct as interest both the share of net cash flow and the share of appreciation in the underlying property that the borrower paid to the lender.

The government lawyers had trouble arguing the arrangement created a partnership between the lender and borrower after agreeing in a court filing at the start of the case that the deal documents created a loan.

Two individuals formed a partnership in 2006 to buy a building on 6.85 acres in Rome, Georgia with the aim of doing some renovations and then leasing the building to business tenants. Home Depot and Ferguson Plumbing already had short-term leases. The local hospital was looking for space to offer physical therapy to hospital patients.

The partnership borrowed the amount needed for the project from Protective Life Insurance Co. The insurance company offered the partnership a choice of two loans: a conventional loan with a floating interest rate or a "participating loan" ***/ continued page 17***

Bonus Tax Credits

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is to identify how much of the equipment was made in US factories.

The origin of subcomponents probably does not matter, but a Senate Finance Committee staff summary left this unclear. The summary released soon after the bill was signed says, "Manufactured products are deemed to have been manufactured in the United States if the adjusted percentage [e.g., 40%] of the total cost of the components *and subcomponents* of the project is attributable to components that are mined, produced, or manufactured in the United States." (Emphasis added.) The Treasury will have the final say in guidance.

Manufacturers who are able to offer products that help developers qualify for the domestic content bonus credit have been asking for premiums.

Developers are asking such manufacturers not only to certify that their products were manufactured (as opposed to assembled) at US factories, but also to recertify to the domestic content after any IRS guidance is issued or else return any premium paid for the equipment.

The domestic content requirements have waiver provisions for cases where use of US-made components would increase the project cost by more than 25% or US-made components are not available in sufficient quantity or quality.

A project cannot waive into a bonus credit, according to the Congressional tax committee staffs. Their view is the waivers are relevant only for avoiding a domestic content penalty, meaning inability for tax-exempt and state and local government entities, the Tennessee Valley Authority, Indian tribes and rural electric cooperatives, and private parties with PTCs for clean hydrogen, carbon capture or domestic manufacturing, to receive full direct cash payments from the IRS for tax credits on projects on which construction starts after 2023. (For more about the direct-pay option, see "Searching for Opportunities in the Inflation Reduction Act" in the August 2022 *NewsWire*.)

LMI Credit

Finally, an additional 10% or 20% investment tax credit can be claimed on some small solar and wind projects with maximum net outputs of less than 5 MWac and related batteries.

The extra credit is 10% for such projects on Indian land or in low-income communities that qualify for new markets tax credits.

It is 20% for such projects that are placed on low-income residential buildings whose tenants qualify for rent subsidies or that provide at least half the "financial benefit of the electricity" to households with incomes below 200% of the poverty line or 80% of the area median gross income.

However, developers must apply to the IRS for an allocation of up to 1,800 megawatts of generating capacity that the IRS has to allocate each year. Any project receiving an allocation must be placed in service within four years.

The Treasury will have to decide what it means to share the financial benefits of the electricity. One way to handle this would be to require that at least half the electricity go to households below the thresholds and that such households not be charged more than other subscribers.

Community solar developers and rooftop solar companies will end up competing for the 1,800-megawatt annual volume cap.

Some tax equity investors are unwilling to accept that projects qualify for bonus credits before the Treasury issues guidance.

Tax Equity

Some tax equity investors are unwilling to fund based on bonus credits until the IRS issues guidance.

However, despite some uncertainties, there may be some projects for which qualification is clear. An example is a project in a clear oil and gas area with above-average unemployment. Another is a project in a census tract or adjoining tract where a coal mine shut after 1999 or a coal-fired generating unit was retired after 2009.

In cases where an investor will not fund yet, the deal documents should require an additional investment after the guidance is issued if qualification is then clear. The tax equity investor may require a legal opinion.

Insurance companies are eager to write tax insurance on qualification.

Another idea that has been discussed in some deals is leaving the bonus credits for the sponsors in the same way that state tax benefits or renewable energy credits often remain with the sponsor because the tax equity investor is unwilling to take them into account in pricing. However, the tax credits would have to be sold by the tax equity partnership and then the cash distributed to the sponsor. Proceeds from selling tax credits do not have to be reported as income. However, the tax-exempt income bumps up partner capital accounts in the same ratio as tax credits would have had to be allocated by the partnership. Thus, 99% of this tax-exempt income would be added to the tax equity investor's capital account, giving it more capacity to absorb depreciation on the project. The sponsor would have to fund any tax indemnity that must be paid to the tax credit buyer in the event the IRS disallows the bonus credits. ◎

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with a lower interest rate of 6.25% but that required signing a separate agreement called an "additional interest agreement" under which the borrower promised to pay 50% of net cash flow during the loan term and 50% of appreciation in the value of the building on the maturity date for the loan or, if earlier, when the property was sold or the loan was refinanced, the property condemned, the loan defaulted or subordinated financing was arranged with another lender.

The lender used the same loan documentation — a note and security agreement — for both types of loans, except the participating loan also required signing the additional interest agreement.

The partnership borrowed $4.4 million in total to cover not only the acquisition cost but also the renovations. The loan covered the entire $2.2 million acquisition price plus another $250,000 in transaction costs. The partnership put down a $50,000 earnest money deposit, but got it back at closing.

The partnership made monthly payments under the loan. The payments were treated as base interest (6.25%) first, then repayment of principal, and then payment of the additional interest.

It sold the building in 2014 for $6.3 million.

The IRS argued that the 50% share of appreciation could not be deducted as interest on grounds that it was paid to the lender in its capacity as a partner. It said either the payment was a return on equity investment by the lender or a "guaranteed payment" not tied to partnership income to the lender in its capacity as a partner.

The court rejected the IRS position. It said the lender did not become a partner.

It said the lender could not be a partner unless it contributed part of the capital or provided services for the project. The court said the government would have had to argue that part of the "loan" was / continued page 19

Recycling and Renewable Energy

by Jenna Goldman, in New York

End-of-life management of renewable energy is both a looming challenge and a potential opportunity.

Developers bidding to supply electricity or storage, manufacturers planning new factories, recycling companies and banks and tax equity investors financing projects should anticipate that there will be changes in law and new regulations to address the challenge.

The International Renewable Energy Agency projects that 78 million metric tons of solar panel waste could accumulate by 2050. The possible recovery of that waste could be worth as much as $15 billion.

The average useful life of a solar PV module is approximately 30 years. A lithium-ion car battery can last as long as 10 to 20 years. Wind turbines have a lifespan of between 20 and 25 years. Although these timelines are an eternity compared to the breakneck speed of development (70% of all active solar energy systems have been deployed within the last five years), putting recycling practices and policies in place now will avert a massive solid waste crisis in the future.

Governments are signaling that one approach to dealing with the future solid waste crisis is to place the responsibility and cost of recycling on manufacturers.

In parallel, new renewable energy technologies will require a significant amount of raw materials. These vital minerals are becoming increasingly difficult to find both because they are finite in quantity and because of recent restrictions on imports from countries without free trade agreements with the US. The minerals used in lithium-ion battery storage, such as cobalt, lithium, manganese and nickel, are non-renewable resources and are procured through carbon-intensive mining, which can be fraught with human rights abuse. The Inflation Reduction Act imposes rigorous sourcing requirements for such minerals in order for manufacturers to be eligible for tax credits.

Developers and sponsors should plan for recycling as they adapt to the growing number of regulations surrounding the recycling and reuse of these assets. In some states and countries, sponsors and developers will be compelled to contemplate the future of the equipment from the onset.

Three recent US statutes have recycling provisions that touch on renewable energy technology manufacturing.

The latest trends in the US and the European Union with respect to compulsory recycling programs also shed light on what manufacturers and developers should anticipate for end-of-life management and resource recovery.

IRA

The largest and most recently enacted of the three new US statutes is the Inflation Reduction Act, signed into law in August 2022. One of the main focuses of the IRA is to encourage domestic manufacturing and deployment of renewable energy technology, along with many other incentives for individuals and industries to reduce greenhouse gas emissions through the transition to renewables. Such massive leaps will be achieved through a variety of tax incentives.

The IRA includes several provisions that specifically address and encourage the recycling of components.

First, section 48C of the US tax code, as amended by the IRA, now earmarks $10 billion in available tax credits for manufacturers who invest in new or upgraded factories that build specified renewable energy technology and components. The definition of "qualifying advanced energy projects" eligible for tax credits has been expanded from facilities that manufacture certain components to include facilities that also recycle qualifying property. Recycling facilities now qualify for tax credits of 30% of the total investment in new or upgraded factories. This is a subtle yet significant change by Congress to put recycling on an equal footing with manufacturing of renewable energy components in the US.

Demand for minerals used in batteries and photovoltaic solar modules will increase as manufacturers ramp up renewable energy equipment production to take advantage of tax credits under the IRA. Suppliers of those necessary minerals, called "applicable critical minerals" and defined more specifically under new section 45X(c)(6) of the US tax code, will now need to comply with certain stringent requirements in order to be eligible for incentives.

Suppliers qualify potentially for a tax credit for 10% of their costs to produce the minerals. The minerals must meet listed purification minimums. They must be produced in the United States or US possessions.

The IRA also has sourcing rules for critical minerals used in electric vehicle batteries for purchasers to claim federal tax credits on such vehicles. The critical minerals must be extracted or processed in a country with which the United States has a free trade agreement or have been recycled in North America. Many minerals used in renewable energy technology are found only in certain countries. Not all of these countries have free trade agreements with the United States or sterling human rights records. This will make procurement of minerals through recycling and reclamation important.

End-of-life management of renewable energy equipment is both a looming challenge and a potential opportunity.

This country of origin condition nods to the seriousness with which Congress and President Biden take international labor concerns. The renewable energy industry was rocked by the ban on importing essential solar panel materials from Xinjiang province in western China over reported forced labor of Uyghurs. Despite major supply-chain challenges that resulted from the ban on these Chinese solar panels, the US held firm on its stance.

CHIPS

The Creating Helpful Incentives to Produce Semiconductors (CHIPS) for America Fund Act, also signed into law in August, includes a $280 billion package of grants and tax credits, with $52 billion set aside for domestic semiconductor manufacturing. Companies that build semiconductor manufacturing plants in the US may be eligible for tax credits of 25% of the invested amount for the taxable year. (For more detail, see "Tax Credits for Semiconductor Manufacturing" in the August 2022 *NewsWire*.)

While semiconductors are most known for their use in computer chips, they are also crucial parts of photovoltaic cells and electric vehicles , and in efficiently transferring electricity generated by wind turbines and hydropower into the electricity grid. Most semiconductors are manufactured in China and Taiwan. Trade disputes and supply chain issues have underscored the importance of domestic manufacturing.

Domestic manufacturing is front and center in the CHIPS Act. However, Congress acknowledged the / continued page 20

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really an equity investment. Instead, the government stipulated at the start of the case that the entire $4.4 million was a loan.

In a 1960 court decision called *Farley Realty*, a US appeals court found that a shared-appreciation loan gave the lender an equity interest, but in that case, there was no fixed maturity date by when the lender had to be paid a share of the appreciation. In this case, the share had to be paid no later than when the loan principal came due.

The court said another factor weighing toward treatment of the appreciation share as interest was that the lender had no real exposure to losses in the supposed partnership. A partner's return rides up and down with how well the business performs.

The court granted the government the fact that the loan was the sole source of capital to undertake the project — the two partners put in only $5 each — cut in favor of treating the lender as a partner, but said it was not enough by itself to reach that conclusion, especially given the government stipulation at the outset that the entire $4.4 million was a loan.

The case is *Deitch v. Commissioner*. The court released the decision in late August.

THE FATE OF A FEMA PROPOSAL to require power plants and other projects, like drinking water and wastewater treatment facilities, to be able to withstand extreme weather events should be decided around November 1.

Most such facilities must be built currently to comply with building codes for risk category I assets. The Federal Emergency Management Agency proposal would bump them to risk category IV.

The international building code ranks buildings and other structures in four risk categories, with IV being the highest, based on the how essential they are to human life. Examples of category IV assets are hospitals, fire and rescue services and emergency storm shelters.

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Recycling

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difficulty of finding raw materials needed to make semiconductors and is requiring recycling programs as conditions to certain grants by the Department of Energy.

The CHIPS Act authorizes grants for recycling programs helium. Helium is one vital element in semiconductors of which the US is a major supplier, but many other elemental or mineral components used in renewable energy technology are mined elsewhere around the globe, introducing another layer of complication to US manufacturing, one that has a possible remedy in reclamation of minerals in decommissioned components. Using helium as an example, the procurement of helium may soon become significantly more difficult, forcing more recovery and recycling. Helium is used not only to make semiconductors, but also in a range of other applications from medical imaging to space exploration to the classic birthday balloon. It is a non-renewable resource that is recovered through intensive drilling into underground gas fields.

So important is helium to modern society that the US created a federal helium reserve system in the 1960's to store helium and ensure that enough will be available for national security purposes. Portions of the reserve are sold each year, and the reserve reportedly contains only enough helium to last until 2025.

In anticipation of potential helium supply shortages, the CHIPS Act directs the Department of Energy to establish a program to reduce the consumption of helium and to encourage helium capture, reuse and recycling. The department will also be required to publish reports on the quantity of helium purchased for projects receiving grants and to provide information on country of origin if helium was imported from outside the United States.

Unlike helium, most other critical materials required to make semiconductors and other components of renewable energy technology are not mined currently in the United States. For example, lithium-ion batteries used in electric vehicles require a significant amount of cobalt. Nearly 70% of the world's supply of cobalt is recovered through nickel mining in the Democratic Republic of the Congo, a nation often cited for human rights abuses in its mining practices. Customs seizures of certain materials due to the human rights records of the countries of origin are a risk.

The CHIPS Act earmarks funds for critical-minerals-mining research and development in the form of grants to universities and non-profits to support innovation that will improve "recycling techniques and technologies that will decrease the energy intensity, waste, potential environmental impact, and costs of those activities."

Bipartisan Infrastructure Law

The Infrastructure Investment and Jobs Act, signed into law in November 2021, covers a wide array of industry development and funding of projects ranging from highway safety to rural broadband access to the updating of potable and wastewater infrastructure.

Notably, the Act sets aside $335 million for the US Department of Energy to implement a lithium-ion battery recycling program. This is an indication that the federal government is serious about getting ahead of the future wave of battery waste.

The Act defines the term "recycling" as the "recovery of materials made from advanced batteries to be reused in similar applications, including extracting, processing, and recoating of battery materials and components."

The new battery material processing grant program will award money to eligible entities for the purpose of expanding battery manufacturing in the United States. Grants will be made to entities that carry out demonstration projects to process battery materials, build new commercial-scale battery material processing facilities, or retrofit and expand existing battery material processing facilities, if located within the US and determined qualified by the DOE. Grants of up to $50 million will be awarded for projects that process battery materials or expand, retrofit or retool existing factories. Up to $100 million may be granted for the construction of new commercial-scale facilities.

The Act authorized a parallel grant program to be run for another office in DOE to encourage manufacturing and recycling of components for advanced battery manufacturing. Grants of up to $50 million may be made for demonstration projects and for updating and retrofitting existing facilities, and up to $100 million for building new commercial-scale manufacturing or recycling facilities. Priority will be given to entities operating in the United States using North American intellectual property and content and to battery recycling projects that it will not export recovered materials to a foreign entity of concern.

The Act also directs the US Environmental Protection Agency to award multiyear grants to entities for research, development and demonstration projects for approaches to increase the reuse and recycling of batteries.

The distinction between the DOE and EPA programs is that EPA will focus on recovering critical minerals from the standpoint of mitigating health and environmental impacts of battery recycling and disposal. Entities eligible for grants under this program are universities, federal and state research agencies, nonprofits, private battery producers, retailers and collectors.

Finally, the Act also encourages recycling of electric vehicle batteries. Two federal agencies — Commerce and DOE — will establish a grant program to improve recycling rates and second-use adoption rates of electric vehicle batteries, to refine of the design of EV batteries to make them more easily recyclable, to establish alternative supply chains for critical materials found in EV batteries, to reduce the cost of manufacturing of batteries, and to mitigate the environmental impact of battery recycling processes. Grants for this program will be awarded based on a competitive, merit-reviewed basis to eligible entities, prioritizing projects located in geographically diverse regions of the US and projects that have the potential for high-volume recycling capabilities, among other metrics.

European Union

While the US is using a carrot to encourage recycling of renewable energy technology components, Europe is using a stick".

The European Union parliament recently adopted a report that lays out a blueprint for more stringent recycling guidelines, specifically for batteries. As of 2019, 51% of portable batteries in the EU have been collected for recycling, but the latest report calls for a more aggressive 70% recycling rate by 2025 and 80% by 2030.

Not only will the EU mandate the recycling of old batteries, but it will also require new batteries to be produced with a minimum of 85% recycled lead, 20% recycled cobalt, 10% recycled lithium and 12% recycled nickel by 2035. Batteries sold into the EU will be required to carry a "battery passport" that must include information about the battery's carbon footprint, recycled content and an overview of any human rights abuses and safeguards in place across the supply chain of the individual battery.

US automobile manufacturers should take note of these stringent requirements and begin considering how best to comply if they wish to continue participating in one of the world's largest markets for electric vehicles. Certain US states are taking notice of the trends in Europe and are implementing similar recycling programs, most prominently in Washington, Illinois and California.

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The solar industry has proposed moving solar power plants to risk category II as an alternative to the category IV classification.

Any change would be made in the international building code starting in 2024.

A letter from 315 clean energy companies to the international standards body, the International Code Council, in October said a category IV classification could push up the cost of wind turbines by about 30%. The Solar Energy Industries Association said compliance with category IV building codes would require projects to be able to withstand 33% stronger wind and 50% stronger earthquakes and winter storms.

SEIA says that FEMA is now supporting its proposal for a category II classification.

CALIFORNIA extended a property tax exemption for solar projects placed in service by the end of 2026.

The projects remain exempted until there is a change in control.

The exemption had been scheduled to expire at the end of 2024. It has been extended multiple times since the 1980s. California Governor Gavin Newsom signed a bill, S.B. 1340, on September 18 extending the exemption, but urged legislators to consider the effect on local tax collections before extending it again after Kern County objected that the exemption shifts the cost of public services used by increasingly well-established solar companies to other property owners.

The California constitution limits property taxes on real property to 1% of the 1975 value or the value upon more recent construction, plus an adjustment for inflation that is limited to 2% a year.

A change in ownership triggers a reassessment to the current value.

Section 73 of the California property tax statute effectively exempts active solar systems from assessment until there is a change in control after the

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Recycling

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Washington State

Washington State requires solar panel manufacturers selling panels after July 1, 2017 for use in the state to take back used panels for recycling. The requirement is in S.B. 5939 enacted in 2017. Implementation is expected to begin on July 1, 2025. Manufacturers will be required to provide for recycling of modules at no cost to the last owner or holder of the panels.

Solar panels covered by the program are all those installed on or connected to buildings, any freestanding off-grid power generation systems, such as EV charging stations or solar-powered street lights, module kits and modules connected to a grid or a utility.

"Manufacturer" is defined broadly under this law and includes seven types of entities. One is an entity with legal ownership of the brand name of the module for sale in or into Washington. Another is an entity that assembles a module using parts manufactured by others for sale in Washington under the assembler's brand name. Another is an entity that resells or has resold modules into Washington under its own brand name. The term includes entities that have manufactured a co-branded module for sale in the state that carries the brand name of both the manufacturer and retailer. The fifth category is an entity that imports or has imported a module into Washington for sale. Category six is an entity that imports the module if the manufacturer does not have a physical presence in the US. Category seven is an entity that sells the module at retail and takes legal responsibility in place of an importer or manufacturer.

Manufacturers who sell modules in the state must submit a stewardship plan within 30 days of first sale of a module in Washington. The plan must describe how manufacturers will cover the costs to take back and recycle and describe how the program will maximize the recovery of mined minerals and other valuable materials while minimizing the environmental impact of the recycling process.

The state must approve the plan and manufacturers must provide annual updates on April 1 each year. Panels without an approved recycling plan have been blocked from sale in Washington since January 2021.

While Washington remains the only state to mandate recycling programs for renewable energy components, other states are beginning to plan for end-of-life management.

Illinois

Illinois has a goal of transitioning to 100 % clean energy by 2050. As part of that effort, the state enacted Public Act 102-1025, dubbed the "Renewable Energy Component Recycling Task Force Act," effective May 27, 2022. The Act establishes a REC recycling task force with instructions to investigate a number the future waste challenges.

It will explore options for recycling as a means of end-of-life management for renewable energy generation components and energy storage devices and consider the economic and environmental costs and benefits associated with each method of recycling. It will assess the expected impact on landfill capacity. It will survey other states' and countries' recycling requirements, including financial assurance requirements for owners, operators, developers and manufacturers. It will identify the new infrastructure necessary. It will make recommendations for end-of-life management for renewable energy components.

The task force must publish a formal report by July 1, 2025.

California

California was an early adopter of incentives for both rooftop and utility-scale solar. California formed a solar initiative in 2006 that granted $3.3 billion in subsidies for the solar industry. Today, between PV solar and solar thermal power, 17.31% of the in-state power generation comes from the sun.

In anticipation of the end of life of those early panels, California adopted new rules loosening its regulations around recycling of solar panels. Panels were classified as hazardous waste and were subject to strict disposal requirements, making the transportation, storage and handling of decommissioned panels difficult. However, the state shifted on January 1, 2021 to treating panels as "universal waste," with the result that handlers will not be subject to storage limits and will be allowed to freely handle the waste (crush, compact, separate and saw). Handlers and owners will still be subject to certain notification and handling requirements, but the reclassification of panels should dramatically reduce the cost of recycling and open doors to innovative recycling opportunities.

Local governments in California are not waiting for the state to adopt formal recycling plans. The City of Santa Monica launched its own successful solar panel recycling pilot program in 2022. With funding from the city, members of the California Conservation Corps went door-to-door collecting old or broken panels and dropped them off at a local electronic recycling facility equipped to process rooftop-sized panels. ◎

Carbon Capture Economics

The Inflation Reduction Act increased a tax credit for capturing carbon oxide emissions and extended the deadline to qualify. The tax credit, even before the latest increase, was already contributing to growing interest in installing carbon capture equipment at ethanol and fertilizer plants, steel mills and petrochemical facilities. More than 200 people attended an Infocast CCS and decarbonization summit in Houston in late July. The following is an edited transcript of a wide-ranging panel discussion on where carbon capture companies are getting traction, the risks in deals and how transactions are being structured.

The panelists are Cindy Crane, CEO of Enchant Energy, Aaron Hood, CFO of Summit Carbon Solutions, Tyler Durham, chief development officer of Navigator CO2 Ventures, Jeremy DeMuth, a managing director of Deloitte Tax, and Bob Purgason, managing director of carbon solutions for Enlink Midstream. The moderator is Keith Martin with Norton Rose Fulbright in Washington.

Low-Hanging Fruit

MR. MARTIN: Cindy Crane, at what types of industrial facilities do the economics work currently for carbon capture, and why don't they work for other types of facilities?

MS. CRANE: The economics seem to work best at ethanol plants. I am working on a carbon capture project at a large coal-fired power plant. We think such projects became economic with the funds that are available in the Biden infrastructure bill for demonstration projects. We just completed a FEED study that validated the economics, so we are excited to move forward.

MR. MARTIN: The economics don't seem to work well at many power plants because of the parasitic load. The amount of electricity that must be used to compress the CO2 for transport is very high. I think at your plant it is something like 30%. Is that the main challenge for power plants?

MS. CRANE: It depends. Our power plant is owned by Enchant Energy. The carbon capture equipment will be owned by a separate company that will be a customer of the power plant for power, steam, water and flue gas. What you might call parasitic load in another context is actually a steady revenue stream for the power plant.

MR. MARTIN: Aaron Hood, Summit Carbon seems to be focusing on ethanol and fertilizer.

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IN OTHER NEWS

initial construction.

Avoiding a change in control is a significant issue in any M&A transaction where California solar projects are involved.

A change of control is considered to occur when more than 50% of both the profits and capital interests in a partnership are transferred. The state focuses on whether someone is gaining control in a transaction rather than someone is losing it.

California clarified in late 2021 that partnership flip transactions, which are the most common way to raise tax equity to finance solar projects, do not trigger property tax reassessments, but left some potential gaps that require attention to detail. (For more information, see "Partnership Flips and California Property Taxes" in the December 2021 *NewsWire* and "California Split-Roll Initiative Upsets Solar Developers" in the June 2020 *NewsWire*.) ◎

— contributed by Keith Martin in Washington

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MR. HOOD: We are focused on all emitters whose emissions we can capture economically in our footprint area. Ethanol and fertilizer plants have the lowest cost to capture today. We are open to other emitters as the economics improve or section 45Q tax credit amounts increase.

MR. MARTIN: What is special about ethanol and fertilizer? Why do they have the lowest cost of capture?

MR. HOOD: They have a relatively pure carbon dioxide emissions stream. Ethanol plants have been capturing CO2 for industrial use for as long as they have been around to make fizzy beverages and dry ice. It is a relatively straightforward process technologically.

MR. MARTIN: Tyler Durham, you came from Schlumberger. It has been on the road pitching its services to capture emissions. Where are you finding that the economics do not work?

MR. DURHAM: The concentrated CO2 emissions streams are the easiest to capture. From a technical perspective, that is the first stop for carbon capture and storage. But it takes more than a pure CO2 emissions stream to make the economics work.

The challenge with ethanol facilities is they are spread out. A big part of any organized effort to capture their emissions is how to tie them together at scale. Contrast that with a post-combustion facility like a power plant where you may be looking at a technical challenge rather than a logistics and infrastructure challenge.

MR. MARTIN: Let's unpack that. There are two CO2 streams in a typical industrial facility. There is a relatively pure one that is pre-combustion and then a dirtier one where the CO2 is mixed in with other gases. It is post-combustion. Is the point that the CO2 is more expensive to extract from a post-combustion stream?

MR. DURHAM: Yes. It is cheaper to complete the separation process with an emissions stream that is highly concentrated CO2. A lot of work is being done on the technology to make it more economic to extract CO2 from post-combustion emissions streams.

Until the technology improves, most of the capture projects will be at ethanol, fertilizer, bio-energy, steam methane reforming and other chemical plants that, by nature, generate highly concentrated CO2 streams.

MR. MARTIN: You anticipated my next question. What will be the next lowest-hanging fruit for carbon capture after ethanol and fertilizer? You included bio-energy on your list. Is that anerobic digestion and renewable natural gas?

MR. DURHAM: Certainly waste to gas will have concentrated streams that may be targets. It will depend on scale and how far they are from infrastructure. We expect to start seeing direct air capture pilot plants.

We also expect to see carbon capture at plants that are producing sustainable aviation fuels and other alternative fuels that are able to go to market only by controlling the carbon intensity of their production processes.

MR. MARTIN: Jeremy DeMuth, you look about to say something.

MR. DEMUTH: In addition to ethanol, ammonia and steam methane reformation, we are also seeing chemical production processes that release a lot of CO2. Then you start to get into the more difficult-to-capture post-combustion sources, such as steel mills. Carbon capture is becoming an environmental imperative for some of these companies.

The lowest-hanging fruit for carbon capture has been ethanol and fertilizer plants and factories in concentrated industrial corridors.

Emerging Business Models

MR. MARTIN: That is a good bridge to the next topic, which is emerging business models. There doesn't seem to be a single business model yet around which everyone has coalesced. The federal government puts a lot of money on the table in the form of tax credits. Every participant in the deal wants a share.

The business model is driven by the commercial deal on who gets what share and how to label the money transfers.

The variations start with who owns the capture equipment. That is where the money comes in the first instance since the capture equipment owner is entitled to the federal tax credits.

Aaron Hood, will Summit Carbon own the capture equipment at ethanol and fertilizer plants?

MR. HOOD: We are using a vertically-integrated model at the 32 ethanol plants with which we have partnered today. What does that mean? It means we own the capture equipment. We build the pipeline. We own the storage facility in North Dakota.

That does a couple of things for us. First, it keeps all the risk under the same roof so that there are fewer players around the table negotiating about risk allocation. Second, our ethanol plant partners do not have to take a view on the potential uplift from the low carbon fuel standard or voluntary carbon markets. We know that biogenic removal credits for voluntary markets are going to be much more valuable than the credits that are available today.

MR. MARTIN: So there is less finger pointing if things go wrong? There is just one party to point to, and that's you?

MR. HOOD: I think there will be plenty of finger pointing, but fewer people pointing the fingers.

MR. MARTIN: Tyler Durham, is that your business proposition as well?

MR. DURHAM: We are a little more flexible on business model. There are cases where we will own the entire chain. There will be other cases where the capture equipment is owned by the industrial facility.

MR. MARTIN: Will you act as both the pipeline and sequestration company?

MR. DURHAM: We will. Potentially all the way from the capture equipment to the sequestration or other use case. We see the voluntary carbon market as part of that. We expect to release some more news later this year on that side and how we see that market developing.

MR. MARTIN: In cases where your customers who are the source of the CO2 keep the capture equipment and therefore the tax credits, do you know if they are planning to use them themselves or to raise third-party tax equity?

MR. DURHAM: We may see both situations. It depends very much on the operator. Some have capacity to use the tax credits and others do not. In the latter case, we will have to bring in a tax equity investor, which adds another cost to the economics.

MR. MARTIN: Cindy Crane, who will own the capture equipment at the San Juan generating station?

MS. CRANE: Enchant Energy will own the equipment from capture all the way to storage. We will also own 95% of the power plant.

We hope to be the carbon capture and storage provider to the industry and are developing a pipeline of other projects. We want to remain flexible with owning a percentage of the emitter itself where it makes sense to do so. We will be looking to monetize the tax credits with tax equity investors, unless Congress enacts a direct-pay alternative.

MR. MARTIN: Did I hear you say you would also sequester the CO2? You will handle that part of it?

MS. CRANE: Yes, although we are open to joint venture partnerships for the transport and storage side. We are working on a CO2 pipeline today that will connect into the Cortez. That will allow flexibility for enhanced oil recovery.

We have also partnered with the New Mexico Institute of Mining and Technology on a carbon safe program. It is doing the work to characterize the geologic formation. We have identified the location of the injection wells. Our joint venture partner is preparing to drill the stratigraphic well, but the EPA class VI injection well permits will be filed in Enchant's name.

MR. MARTIN: Jeremy DeMuth, it looks like you want to add something.

MR. DEMUTH: The IRS issued a helpful revenue ruling last year that lets the tax credits be claimed by someone who owns at least one component of a single process train of carbon capture equipment. A single process train means everything from capture all the way through compression and preparing for transport.

That means you may have different companies owning different pieces of a single process train. It allows flexibility to have one party do the carbon capture while another can claim the tax credits.

MR. MARTIN: Let me ask on that. The problem was a lot of factories have a gas separation unit that is embedded in the factory and is as old as the factory. The IRS regulations say the tax credits belong to the person who owns the capture equipment, but it is impossible to take that piece out and give it to a tax equity investor whom you want to claim the tax credits. So, as you said, the IRS concluded last July that a person who owns at least one piece of the capture train and has responsibility for disposing of the CO2 can claim the tax credits.

How little of the capture train do you feel comfortable saying that person can own? Most tax advisors, I imagine, will be uncomfortable with owning a single compressor.

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MR. DEMUTH: You have a lot of flexibility because of the revenue ruling, but I don't think that it would be good to push it too close to the edge.

Revenue Streams

MR. MARTIN: Let's turn to revenue sources. There are at least two revenue streams coming into these deals. One is a federal tax credit of $50 a metric ton for captured CO2 that is sequestered permanently underground and $35 where the CO2 is used for enhanced oil recovery or to make a commercial product. [Editor's note: The Inflation Reduction Act increased the tax credit amounts to $85 and $60.]

Aaron Hood mentioned an uplift for LCFS credits in California. That is a potential benefit for ethanol producers whose ethanol is being supplied, in theory, to the California market. But if they capture the carbon emissions, the credits are worth more because the ethanol will be assigned a lower carbon intensity. What about other revenue streams? Cindy Crane, you mentioned one.

MS. CRANE: The voluntary credit market is just getting started. Direct pay is another revenue source that allows the section 45Q tax credits at the federal level to be converted into cash without having to go through tax equity investors.

MR. MARTIN: The voluntary credit market is the carbon offset market?

MS. CRANE: Yes. Many companies with carbon emissions will be looking for offset credits in circumstances where it is not economic or practical for them to decarbonize directly. While we are not counting on additional revenue from it in our pro formas, we hope to see that market evolve over the next two to four years.

MR. MARTIN: You made an important point, which is it is hard to take revenue streams into account during financing unless they are predictable. Aaron Hood, how predictable is the LCFS uplift?

MR. HOOD: It is not particularly predictable, but it has expanded beyond California into Washington, Oregon and all of Canada. A bunch of other US states are looking at low carbon fuel standards and building what has effectively become a compliance market.

We think that has great long-term value for us alongside the voluntary market.

Our project alone will capture close to 10 million tons of CO2 a year. It has the potential to change that market fundamentally. Obviously, there are ethanol producers who cannot ship their product physically to California. As the low carbon fuel markets expand across North America, the entire ethanol industry will benefit.

Ethanol has a carbon intensity in the mid-60% range. Capturing the CO2 reduces the carbon intensity by 30 or more points. It is not as if this makes only a marginal difference. It is a massive step change.

MR. MARTIN: We have seen revenue figures in projects where the LCFS uplift is worth more than the federal tax credits. Are you seeing that as well? What are the relative values?

MR. HOOD: LCFS credits have varied from $175 to around $100. They are a significant revenue source. Our projected operating expense to transport and sequester CO2 is about $25 a ton.

However, as you said, it has been challenging to get lenders to credit the LCFS uplift or voluntary offset credits toward any financing.

By having a vertically-integrated model, we are not nearly as reliant on that revenue stream. It is an equity risk and potential upside. It is not a risk we are asking the lenders or the tax equity partners to take.

MR. MARTIN: Where the CO2 is used for enhanced oil recovery, does the EOR company pay for the CO2, or is it paid to dispose of it?

MS. CRANE: The EOR company needs to pay to get the economics to work.

MR. MARTIN: What about where CO2 is turned into a usable commercial product? That must be another revenue stream.

MR. DEMUTH: We certainly see revenue streams from use of captured CO2 to make commercial products. We do a lot of work at Deloitte on the lifecycle greenhouse emissions analyses that are required in such situations. Aaron said earlier that people have been capturing CO2 for a long time and using it in dozens of different applications, from carbonated beverages to fire extinguishers to several intermediate chemicals. There is a big demand for CO2. It affects how much someone is willing to pay for it.

There has been a CO2 shortage in this country for the last couple years. Think about the amount of dry ice that has been needed for COVID vaccines.

MR. PURGASON: We have a transport-only role in our project in Louisiana, but we also have a project with BVK Corporation in the Barnett shale area in north Texas. Matheson will end up buying some of the CO2 to supply to the beverage market, and

New tax credits as high as $180 a ton for direct air capture and $85 for sequestration will expand the universe of potential capture projects.

we will be paid a fee to bury the rest underground.

We spend a lot of time on the financial engineering around the projects, but in my mind, carbon capture is a regional business. You look at the nearby opportunities to use the captured CO2.

In Louisiana, there is a 200-mile corridor from Baton Rouge to New Orleans with many different emission sources, including ammonia, ethanol, methanol and ethylene, that need compression, transportation via pipeline and sequestration to get into the ground.

MR. MARTIN: We talked about low hanging fruit earlier. You are pointing out the low hanging fruit may not only be ethanol and fertilizer, but also where you have concentrated CO2 emissions and you can move them easily.

MR. DURHAM: One thing we have not mentioned is we expect companies to experiment with pilot-scale efforts over the next few years to use CO2 to make alternative fuels and to make new chemicals as potential replacements for chemicals used in more traditional chemical processing operations. That is another potential upside.

Business Propositions

MR. MARTIN: All of this explains why most of the new carbon capture projects are in the Midwest, where there is lots of ethanol, and Louisiana and the Houston ship channel, where there are petrochemical facilities, LNG export terminals, steel mills and concentrated industrial corridors.

We talked about revenue streams: the tax credits are a large dollar amount. They are probably the most predictable revenue stream. There is an LCFS uplift. There may be carbon offset credits. There may be other revenue sources, like payments for buy CO2 to use in enhanced oil recovery or to make commercial products.

How does the revenue get split among the various deal participants? Is there a way of breaking it down among the emissions source, the capture equipment owner, the pipeline and the sequestration company? Or is it too early?

MR. HOOD: We have constructed a business model where we are not asking our ethanol partners to invest capital upfront. Many of our ethanol partners are single-plant facilities that are owned by the farmers that produce the corn that is sold to the ethanol plant. A single plant can have hundreds of shareholders. The plants have other things to do with their capital, whether it is distributing it to their owners or use for yield optimization in their plants. The way our revenue model works is we share the uplift with them after our operating expenses have been paid.

They have an infinite return on capital from the carbon capture project. They might not make as many dollars as they would if they were paying a tolling fee to us and installing their own capture equipment, but our business model dramatically lowers their complexity. They don't have to worry about becoming carbon capture experts. They can worry about growing corn and making ethanol in as efficient manner possible. We are an agriculture company at the end of the day, and decarbonizing the agricultural industry is something we thought about when we conceived this company.

MR. MARTIN: You don't pay anything to the fertilizer or ethanol plant. Rather, it pays you to come capture the carbon, and the payment is a function of the LCFS uplift it gets. Is that right?

MR. HOOD: There is an alignment of interests. It is a sharing of the returns from the project. We don't ask them to pay us. We don't pay them for their CO2. We pay: obviously we are going to spend $4.5 billion in capital expense. The pipelines are $3.5 billion out of the $4.5 billion when you run 2,000 miles of pipe.

MR. MARTIN: Tyler Durham, what is the Navigator business proposition?

MR. DURHAM: The revenue split may look very different in different places. For example, projects in the Middle East will be very competitive on price for the sequestration part, cheaper than in some parts of the US.

In the US, things will look different in */ continued page 28*

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the Gulf Coast than they do in California. It is more challenging in California to do a seismic survey, increasing the cost and pushing out the timeline to complete a project.

MR. MARTIN: Does Navigator follow the Summit Carbon model, where it is paid a share of the LCFS uplift?

MR. DURHAM: We have a couple ways to do that. We will do a fee-for-service, over-the-fence type arrangement where they pay us, we take the CO2 and they never see it. It is more closely related to a waste-disposal model. Alternatively, we may accept a smaller fee in exchange for a share of the upside.

MS. CRANE: We are a little different because—

MR. MARTIN: You are keeping it all.

MRS. CRANE: For San Juan, yes, that is correct. But we are different because our carbon capture company relies on products that it needs from the power plant that is the source of the CO2 emissions. We have a good relationship between the carbon capture company and the power plant because we need its water, its power and its steam. And, by the way, we need the flue gas so that we can decarbonize the power plant.

The price we pay as the carbon capture company for all of that has to keep the power plant economic, meaning the power plant has to be able to attract its own capital and invest in maintenance of its assets.

MR. MARTIN: Jeremy DeMuth, are you aware of any tax equity deals that have closed?

MR. DEMUTH: The word on the street is one and perhaps two have signed documents. That may be high. We know of a number of deals that are in late-stage negotiations.

MR. MARTIN: One, maybe two, expected to close this year, but not yet closed?

MR. DEMUTH: That's right.

Risks

MR. MARTIN: Let's talk about risks. One of the biggest risks is that the emissions source, the factory, the ethanol plant, will shut down, eliminating the principal source of revenue. The tax credits run for 12 years. How is that risk being handled in deals?

MS. CRANE: In our deal, the carbon capture company is an anchor tenant of the power plant. Having the majority of the power contracted is a more favorable financing scenario.

MR. MARTIN: Aaron Hood, how is the shutdown risk being handled by Summit Carbon?

MR. HOOD: We don't think the ethanol industry is going anywhere. Even under the most aggressive forecasts of how quickly the US will electrify the transportation sector, the US will still need a significant volume of transportation fuels for the full tax credit period.

Even if you cut the amount of ethanol needed in half, the Midwestern ethanol plants that are our focus are in the corn belt and the most efficient US producer of ethanol. The cheaper your corn, the better your position in the industry.

Having a portfolio of 30+ plants takes away a lot of the focus around what happens if I have a fire or my plant gets hit by tornado. If we were dealing with one or two plants, it would make things more complicated for sure. Having a large portfolio takes that off the table. Our largest single plant accounts for 4% to 5% of the total CO2. Having $6 billion worth of tax credits to monetize on the low side creates some other interesting issues.

MR. DURHAM: I agree that scale is the way to deal with shutdown risk.

We have 11 million tons a year of CO2 emissions under contract at this point. Our partners include Poet and Valero, two of the three largest ethanol producers in the country. We don't think they are going anywhere.

MR. HOOD: Unlike oil and gas where different pieces of the value chain have been perfectly willing to put each other out of business for a buck, corn and ethanol go together in a way that you can't stop making ethanol or the whole system comes apart. The farmers have to sell their corn somewhere. It is not what you see in oilfield services.

MR. MARTIN: Let's move to another risk, which is big capital outlays are required to install the capture equipment, build the pipeline and put in the well sequestration facility. If there are two parties on either side — one owns the capture equipment, somebody else owns the pipeline and does the sequestration — it is a chicken-and-egg problem. Neither wants to spend money unless it is assured that the other is on track. How is this being handled?

MR. PURGASON: We look at it just like our traditional pipeline business, which is we look for some sort of volume commitments that produce a minimum capital return and then share the upside from volume growth. Fundamentally it is not if we build it, you will come type of opportunity. It is a big guys' game. You have to step up and commit to something.

MR. MARTIN: So both sides commit to each other. What happens if one fails to perform or is delayed?

MR. PURGASON: Both parties are looking for long-term returns on their capital before they put it out.

MR. DEMUTH: Call it critical mass, both in terms on the supply side of CO_2 as well as the destination side. If you are in a place like Louisiana with many potential sources of CO_2 clustered together, that helps in terms of hedging if the CO_2 source happens to have an issue.

You might have another potential offtaker connected to the pipeline that can use the CO_2 if something happens on the disposal side. Having that critical mass not just on the source of the CO_2, but also on the back end is important because it means there will be fallback options.

MR. MARTIN: Another risk is one of three things must be done with the CO_2 to claim tax credits. Either it has to be buried permanently underground, it has to be used for enhanced oil recovery, or it has to be used to make a product that can be sold in the commercial market.

The market has not yet coalesced around a single deal structure.

Let's say it's buried. It has to stay there permanently. If it leaks within the first three years, then the IRS will ask for some of the tax credits back. How is that risk being handled in deals?

MS. CRANE: The insurers are developing products to address this. We are not mature enough as a market to have put those to the test yet.

MR. MARTIN: Have the tax insurers given you any sense of what the premiums will be?

MRS. CRANE: If they did, you would have to threaten bodily harm to get the information.

MR. HOOD: Before we get to recapture risk, we should talk about permitting risk for sequestration, which is to me the elephant in the room.

MR. MARTIN: Be my guest. How long does it take to get the permits?

MR. HOOD: It depends on whether you are in North Dakota. North Dakota has class VI primacy. We announced a joint development agreement with Minnkota, an electric cooperative. It has a permit for its five-million-ton-per-year Tundra East project, and it should receive the permit for its Tundra West project in the next 60 days.

Minnkota had a similar situation where it had to put out a tremendous amount of capital — probably a billion dollars — that will probably have to be borne by the ratepayers if the project fails to advance. We help Minnkota de-risk its sequestration effort by paying the capital costs up front and then having Minnkota pay us back over time as we inject CO_2 into the ground.

It was a great move not only for Minnkota, but also for us. It accelerated our development timetable by taking the class VI permitting issue off the table.

We have acquired about 130,000 acres of pore space adjacent to the Tundra facilities, which is about a billion tons of storage capacity, so we think of it as a long-term asset. As direct air capture becomes a reality and carbon capture at other emitters like coal-fired power plants becomes economic, we will have plenty of storage capacity.

It is not just class VI primacy that helps; it is also amalgamation and having the state take over the risks of CO_2 leakage 10 years after you cease operations. The infrastructure is there, and helpful legal decisions have already been made.

You can't have one landowner holding up for more pore space. The cake has to be baked so you can have certainty. We have bought a third of our rights-of-way for our 2,000 mile pipeline. We could never spend money on rights-of-way if we did not have certainty around our class VI permits.

MR. MARTIN: Tyler Durham, where is Navigator planning to inject the CO_2?

MR. DURHAM: We have filed our / continued page 30

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first class VI permits for sites in Illinois.

MR. MARTIN: We have heard it takes 18 to 24 months to get a class VI well permit. Does that sound right?

MR. DURHAM: That is not an unreasonable estimate. We expect there to be a rigorous review. The Mount Simon site in Illinois is a formation that has already been used and EPA is familiar with it, so those are factors that work in our favor.

MR. MARTIN: Bob Purgason, where a pipeline has to be built, how long should one assume it will take? Does it depend on the state?

MR. PURGASON: It depends on the state and the location within the state. Are you building in a marsh or on dry land? In Louisiana, it is easier to build in the northern part of the state than it is to build in the Mississippi Delta. Eighteen months is a typical project timeline, but it depends on what you already have in place. Having rights of way and existing pipeline corridors can shorten the time period.

MR. MARTIN: I didn't get an answer to what happens to the tax credit recapture risk if the CO2 leaks from underground storage. The sequestration company bears that risk, correct?

MS. CRANE: Agreed

MR. DURHAM: Agreed, but without disclosing the premiums that we have been quoted, we think that risk will be insured.

MR. HOOD: I agree. Geologically, the risk is not as significant as people thought before they started learning about this in more detail.

Other Impediments

MR. MARTIN: So you two plan to buy insurance.

What about environmental liability associated with an underground leak of the CO2. Is that a real issue? The sequestration company takes that responsibility too. Is there cap on its liability?

MS. CRANE: Where you are doing business matters. States like North Dakota and Wyoming have not just primacy, but also laws in place to deal with the transfer of CO2 liability after CO2 has been injected in the ground. The states that are really at the forefront are doing what they need to incentivize and give security for industry to decarbonize.

We are trying to push a similar bill at the federal level. We are also pushing for legislation in New Mexico.

MR. MARTIN: Protection from environmental exposure?

MRS. CRANE: Yes, after injection. Transfer that liability to the state.

MR. MARTIN: The fact that you are working on a bill suggests you think it is a real issue.

MRS. CRANE: Whether it is a real or merely perceived issue, the industry will want protection.

MR. HOOD: The more experience particular states have with oil and gas, the easier it is for them to get their hands around this. States like Louisiana, the Dakotas and Wyoming have been poking holes in the ground for 75 years. They are not jacked up about this. It is CO2.

MR. DURHAM: I agree with the exception of California.

MR. HOOD: The one good thing about California is CARB is really interested in carbon sequestration, so it wants these projects to succeed. It has been working hard with the EERC in North Dakota to accelerate the rulemaking around this. CARB has been pretty open minded about avoiding rules that are ridiculous and unrealistic.

MR. MARTIN: Bob Purgason, we all know how hard it is to build gas pipelines and electric transmission lines. Can eminent domain be used to site CO2 pipelines?

MR. PURGASON: It depends on the state, but there is no broad federal blanket, FERC-type eminent domain process. You have to have local engagement and make sure that the people are satisfied that you are going to take care of things. That is the way to get the pipeline in.

MR. MARTIN: Are the pipelines common carriers? Do they have to post a tariff? Is there a risk that anybody can knock on the door and say he or she wants to move CO2 on your pipeline?

MR. PURGASON: CO2 pipelines are not common carriers in Louisiana. But we are keen to take all comers and create the opportunity to move additional CO2.

MR. MARTIN: What about Summit Carbon and Navigator? Are your pipelines common carriers?

MR. HOOD: We will be a common carrier. The one complexity with CO2, unlike gas or oil, is you have to have something to do with it at the other end of the pipe. If you don't have storage, that is a problem.

I think there is a very low chance of somebody who has arranged independently for storage trying to put CO2 in our pipeline. That said, we will take any emission source we can get.

MR. MARTIN: So there is no reason at the moment for people to move CO2 on your pipeline unless they have contracted with you.

Is another issue that tax equity investors who will monetize tax credits will not want to continue funding if the IRS comes in on audit and disallows some of the tax credits? More than half the section 45Q tax credits claimed in the past have been disallowed by the IRS, but due to faulty paperwork. Presumably nobody will do that again. How is the market dealing with this risk?

MS. CRANE: We are obviously not far enough down the road with the tax equity investors, but in reference to prior discussions you and I have had about other tax equity deals, I think there is more room in structuring section 45Q deals to provide the tax equity investor flexibility to manage risk. I think that's one of the strong things about 45Q. For example, one way for the investor to shed part of the risk is to use a pay-go structure.

MR. DEMUTH: I think that's right. The IRS put out a revenue procedure that allows flexibility to make close to half the tax equity investment contingent on tax credits.

MR. MARTIN: Let me ask the panel first, and then the audience, are there any other risks we have not discussed this morning?

MR. DURHAM: The legacy well situation. People whose equipment is on the surface sometimes fail to look at the subsurface. States like Louisiana have decades of experience with oil and gas wells. We have seen well diagrams from the 1940s and 1950s with a cartoon fish drawn and a few notes that say that something was left in the hole. When you have that, you end up in a discussion with the US Environmental Protection Agency about how you are going to remediate the legacy wells.

Those states are more comfortable with drilling, but they are also more fraught with legacy challenges that you will uncover as you build the sequestration site.

MR. MARTIN: Do you lock in the entire pore space or do you share it with someone else? You are also mixing CO2 emissions from lots of people, so I imagine if there is a leak, you split the burden among all the CO2 sources.

MR. DURHAM: There will certainly be complications. There will also be places where there is adjacent pore space where both parties are injecting into the same formation side by side. There are lots of unknowns around that part of the business.

Audience Questions

MR. MARTIN: Before we move to a lightning round about our panelists' projects, let me ask the audience whether it has any questions.

MS. GARCIA: We have posted a number of audience questions on the screen. The first question is for Tyler Durham and Aaron Hood. Is a section 45Q tax credit of $50 a ton enough to support the entire value chain, or do you need to rely on other incentives?

MR. HOOD: I think $50 works pretty well. You need to have some monetization of your carbon attributes in low carbon fuel markets or voluntary offset market. You don't need heroic amounts of revenue from that. You need some but not that much.

You need a lot of scale. We are 9.5 million tons of CO2 a year. We are building expensive transportation infrastructure. We would like to upsize it as much as possible for business reasons and because it is the right thing to do from a policy perspective, but you can only finance what you can finance.

MR. DURHAM: What Aaron said holds true for concentrated sources. For post-combustion gas streams where the CO2 is more expensive to remove, the tax credit has to be much higher.

And to contradict an earlier panel, I think one million tons a year is too small. The economics at that scale are very challenging even on the sequestration side. You are likely to need two wells to do a million-ton-a-year project. Once you get to five million tons, you have some redundancy. Once you get to 10 or 15 million tons, then you really start to see economies of scale.

MS. GARCIA: The next question is for Cindy Crane. If CCS gets qualified into the voluntary credit offset market, who gets the benefit? The emissions source or the capture facility?

MS. CRANE: In a voluntary offset market, you are basically selling an offset credit to another emitter to offset its emissions. The buyer has the benefit of the offset credit.

MR. HOOD: No double dipping, right? If you monetize in the low carbon fuel market by getting an uplift for reduced carbon intensity of your fuel, you can't then monetize the carbon reduction in the voluntary offset market.

MS. CRANE: Correct. It is no different than renewable energy credits. We expect the same type of market to evolve. Once you retire a REC, you retire a REC. It would be the same thing in the voluntary offset market.

MS. GARCIA: The next question is for Bob Purgason. There are mixed reviews of repurposing pipelines for CO2 transmission. Where is repurposing better than greenfield?

MR. PURGASON: A good rule of thumb is that old pipe beats new pipe. If you can convert an existing pipeline to carry CO2, it is better than trying to build a new pipeline.

The limitation is the unique properties of CO2. It turns into a liquid-like state above 1,050 pounds of pressure. Therefore, if you plan to transport it at very high pressures over long distances, you need a new-style high-pressure pipe to do that efficiently. In Louisiana, we are using 70s-vintage */ continued page 32*

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pipe with nominal 1,000-pound operating pressure.

Stay below that pressure. It takes larger diameter pipes, but these pipes were built to take shelf gas and now the gas comes from the Marcellus formation, Haynesville or somewhere else. We have ample pipe capacity that we can use, but when we go to a longer transport or to a sequestration site where the CO2 will be injected into a well, it will be new pipe because it requires a 2,500-pound pressure design, and we need modern steel to do that.

Enchant Energy

MR. MARTIN: Let's move to a lightning round. I want to ask each of the panelists a few questions. Short answers. Cindy Crane, let's start with you. You have an 847-megawatt San Juan generating station in New Mexico where you want to attach carbon capture on the back end. That plant was scheduled to shut down on June 30 this year. Did it?

MS. CRANE: It did not. One unit was laid up and is being maintained to be brought back. The owners that are exiting needed power for the summer. They were fearful of rolling brownouts and blackouts, so they extended their operations through September.

MR. MARTIN: That is true of one of the four units? There were two to get to 847 megawatts.

MS. CRANE: That's correct.

MR. MARTIN: Farmington, which is a town nearby, owns 5% of the power plant. Public Service Company of New Mexico, the local utility, owned 95%. Does Farmington now own the whole thing? Farmington had an option to buy the 95% PNM share for a dollar.

MS. CRANE: Farmington owns 5%, but there are four other utilities that own the remaining 95% of those two units. Farmington has an option to buy the 95% interest, and we have a rights transfer agreement with the City of Farmington. Those other owners are still in the plant taking the power offtake through September 30. The City of Farmington still has an option to buy the 95%.

MR. MARTIN: Installation of the capture equipment was expected to be completed this year. That was your original plan. Now it looks like the project is behind schedule and it will be 2025 before the capture equipment is fully installed. Is that still the plan?

MS. CRANE: The pandemic happened and schedules across the board were affected. Our FEED study was completed in June. It was filed with the US Department of Energy, and we are going through the final stage on the FEED study. There is a revised schedule for the project that is not public yet, but we are also seeing order backlogs for equipment. Compressors can take 113 weeks for delivery

MR. MARTIN: You plan to operate the power plant as a merchant power plant, if you do take it over. PNM does not want the power. The CO2 emissions I read somewhere to generate electricity are 2,000 pounds per megawatt hour. The state has a ceiling of 845 pounds that, I think, takes effect in January 2023. Your plan ultimately is to get emissions down to about 215 pounds, but not till 2025. How will this work as a merchant power plant given the state ceiling?

MS. CRANE: Coal plants operate typically in the 2,200 pounds-per-megawatt-hour range. The New Mexico "Energy Transition Act" sets a minimum threshold of 1,100 pounds per MWh. The rules around the Energy Transition Act on CO2 intensity are just now being promulgated. We expect those to be finalized by the end of October. We are working with the secretary of the environment in New Mexico on the compliance

Two major roll-up transactions in the Midwest have locked in more than 20 million tons of CO2 a year.

structure. We also prepared a piece of legislation that would extend the date to allow a true energy transition to occur.

MR. MARTIN: I see you have more than a fulltime job. You are also in discussions with the US Department of Energy for a $906 million loan guarantee. Where do those discussions stand?

MS. CRANE: You have been reading some of our early literature. Where we are on financing is we have updated our economic models with all of the FEED outputs. We are looking at the financing stack. We are preparing to respond to the Department of Energy's demonstration project request for proposals. As soon as it gets issued, we plan to file an application for a funding grant, and then we will fill in the stack from there

MR. MARTIN: I also read you have a Navajo investment.

MS. CRANE: Yes, we do. The San Juan plant is surrounded by five tribes, of which the Navajo Nation is the largest. San Juan plant and the mine adjacent to it currently employ a significant number of Native American workers. The Navajo transitional energy company NTEC invested in Enchant. We are working with it to see how our technology can be applied to save other jobs for the Navajo Nation.

Summit Carbon

MR. MARTIN: Aaron Hood, rapid fire. At last count, you had 32 ethanol plants signed up. Is that still the right number?

MR. HOOD: Yes.

MR. MARTIN: Is your focus solely emissions from ethanol or also fertilizer?

MR. HOOD: We will talk to anybody in our footprint that we think can credibly capture within the time frame in which we are operating or in the future to the extent we have excess capacity.

MR. MARTIN: You said you are going to bury the CO2 in North Dakota and you have the class VI permit at this point, correct?

MR. HOOD: Yes, we have one in conjunction with our joint development agreement with Minnkota, and we have a series of other permits. North Dakota has been approving permits if they are properly put together in six to seven months. We have been granted several.

MR. MARTIN: At what stage is the pipeline you are planning to build across five states?

MR. HOOD: We own about a third of the rights of way. Our pipeline permits are in South Dakota and Iowa. There is no state-level permit in Nebraska. We will submit our permit in North Dakota shortly, as well as our core districts that we need and a few other ones. We have something like 6,000 crossing permits and little things like that to clean up. So if anybody wants to come help make crossing permits, you can. There is plenty of work to do.

We talked about eminent domain briefly. You had better buy a lot of rights-of-way before you start talking about eminent domain. It is not written down anywhere, but if you can't buy most of your rights-of-way on a voluntary basis, it will be a tough permitting process.

MR. MARTIN: You said earlier how much the pipeline will cost to build, but it is worth repeating. Also, how many of millions of tons of CO2 a year do you have tied up at this point?

MR. HOOD: A little over nine million tons. It is about a $4.5 billion project, with $3.5 billion in the pipe and the rest in sequestration and other costs.

Navigator

MR. MARTIN: Tyler Durham, Navigator signed a letter of intent with Poet, the largest US ethanol producer, to move five million metric tons a year of CO2. How many tons of CO2 do you have locked up at this point in total?

MR. DURHAM: Just over 11 million tons under contract. We expect that to climb to 15, which is the planned size for the project.

MR. MARTIN: You said earlier you plan to bury the CO2 in Illinois.

MR. DURHAM: We filed our first six class VI permit applications in Illinois. We will have at least that many more to get to scale for the full project.

MR. MARTIN: Jeremy DeMuth, an investor usually cannot claim tax benefits if that's all he is getting out of the deal. Usually people want a cash-on-cash return. In some of these deals, there is nothing but the tax credits. How comfortable are you that the investors can claim on that basis?

MR. DEMUTH: I think that is a real issue. If your only return is from tax credits, you will not fall in the safe harbor the IRS published in a revenue procedure. Either the IRS will have to revise the revenue procedure or you are going to have to be comfortable operating outside the safe harbor. It is certainly an issue and certainly something that we would like to see the IRS resolve.

MR. MARTIN: The tax credit can be passed through by the owner of the capture equipment to the sequestration company. Have you seen this election used? Do you expect it to be used?

MR. DEMUTH: We have seen it used. It is potentially helpful because you are not dealing with / continued page 32

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partnership allocations and the risks associated with them. There is some administrative complexity. You don't really want to bank on someone else making the election on their return and then waiting to file your return until that someone else has made the election.

MR. MARTIN: Bob Purgason, how will your pipeline be compensated for moving CO2?

MR. PURGASON: We are basically a fixed-fee pipeline. We would love to take a share of the tax credit uplifts, but that is usually not on the table.

MR. MARTIN: What sort of deliver-or-pay requirement will there be? You mentioned we are all big boys. Emitters will have to step up to some sort of commitment.

MR. PURGASON: To meet minimum required returns on capital, there will have to be a volume commitment.

MR. MARTIN: For a minimum percentage of what you expect to receive ultimately? Is it 30%? 50%?

MR. PURGASON: It varies based on the size of the commitment.

MR. MARTIN: What happens if there are line losses with the result that you don't get the CO2 to the field where it is supposed to be sequestered. Tax credits cannot be claimed for capturing CO2 that is not sequestered.

MR. PURGASON: There will be shrinkage that will be dealt with in the contract. The capture company will not be able to claim tax credits on 100% of the captured emissions.

MR. MARTIN: Some people would say it is your risk because you are moving the CO2, but what do you think is an appropriate shrinkage percentage before you are called to account?

MR. PURGASON: It is a single digit kind of percentage. ◎

US Offshore Wind Lease Issues

by John F. Young, in Chicago

Offshore wind developers bidding in federal auctions of sites off the US coast commit to a time-consuming and expensive process.

The Biden administration set a goal last year of deploying 30,000 megawatts of offshore wind capacity by 2030.

Two major offshore auctions have already taken place in 2022, with a third expected in the fourth quarter. The US government leased nearly half a million acres of the Atlantic outer continental shelf in the New York Bight auction in February 2022. Fourteen bidders competed to develop six areas in the New York Bight between New Jersey and Long Island. The auction collected $4.37 billion for 5,600 megawatts of potential new offshore wind development. The government awarded another 110,000 acres for lease in the Carolina Long Bay offshore wind auction in May 2022. A California wind auction is scheduled for early December.

Large federal tax credits will help encourage construction of projects. The Inflation Reduction Act enacted in August allows at least a 30% investment tax credit on such projects — or production tax credits on the electricity output for 10 years — that start construction by sometime in the mid-2030s. The tax credits could reach 40% or higher, depending on the location of the onshore parts of the project and how much domestic content is used.

However, the Inflation Reduction Act may complicate future lease auctions. The Bureau of Ocean Energy Management (BOEM) cannot lease new areas for offshore wind development unless it offered at least 60 million acres for oil and gas leasing the previous year and signed at least one lease from that auction. This could delay the California auction.

BOEM is authorized by the Outer Continental Shelf Lands Act to lease portions of the outer continental shelf.

Leases are documented using an October 2016 form called the "Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf" (Form BOEM-0008). BOEM proposes to alter certain provisions of the form for certain auctions.

Non-Negotiable

The form of lease is provided with the proposed notice of sale.

Interested parties are invited to submit comments about the lease form proposed for a particular auction. A final notice of sale is then issued containing the final lease form. An auction is held, winners are announced and the lease is sent to the winner bidder for execution within 10 business days after the award.

Auctions are held only in cases where BOEM determines that more than one developer wants the site. In cases where no competitive interest exists, BOEM may negotiate a lease with the sole developer after consultation with federal agencies, state and local governments and Indian tribes.

BOEM has held eight competitive lease auctions and has only issued two non-competitive leases, one of which was subsequently relinquished.

BOEM has authority to lease areas in federal jurisdictional waters, meaning for the area between three and 200 miles off the US coast.

The leases are subject not only to existing US statutes and regulations, but also any future such statutes and regulations that do not contradict or conflict with an express provision of the lease. Future enacted statutes or regulations could impose new obligations with significantly increased development or compliance costs.

Two Major Plans

The lease grants the lessee the right to occupy an agreed portion of the US outer continental shelf only after a site assessment plan (SAP) and a construction and operations plan (COP) have been approved by BOEM.

These take time to prepare and can be rejected by BOEM in three situations. One is if the lessee's activities would have adverse environmental consequences. Another is if the SAP and COP do not provide adequation protection for safety, prevention of waste, natural resource conservation or coordination with federal agencies or national security interests. The third situation is if the proposed activities would interfere with reasonable other uses of the high seas.

Any BOEM rejection must explain the reasons. The developer can submit revisions.

Development and approval of the SAP and COP are detailed and lengthy processes, taking years to complete. The two plans can only be submitted after complying with site assessment and consultation requirements in the lease.

The lease includes significant coordination, consultation and reporting requirements.

The lessee must make reasonable efforts to consult with, and take steps to minimize potential adverse effects on, a long list of parties that may be affected by the project. The list includes coastal communities, commercial and recreational fishermen, research institutions, Indian tribes, the shipping industry, submarine cable operators, other ocean users and "underserved communities" as defined in section 2 of Executive Order 13985.

There are at least nine separate consultation, planning and reporting obligations of the lessee.

The lessee must develop a draft fisheries communication plan (FCP) within 120 days after lease execution, including strategies for communicating with fisheries and for distributing notices to licensed fisheries and other stakeholders, the identity of the lessee's fisheries liaison, status of discussions with stakeholders, proposed effort to reduce adverse effects on fisheries, processes for filing complaints to the lessee and efforts to mitigate any impacts. The lessee must notify BOEM two weeks before any survey and report annually on any complaints filed.

The lessee is also required to submit a draft native American tribal communications plan (NATCP) and meet with any affected federally-recognized tribes within 120 days after lease execution. The NATCP must specify the lessee's plans for communicating with tribes and disseminating information to tribes and must identify the lessee's tribal liaison and protocols for regular tribal engagement both in type and frequency. The affected tribes must be invited to help with drafting the NATCP.

The lessee must also develop an agency communication plan (ACP) with details of the lessee's plans for active communication and collaboration with all federal, state and local agencies having jurisdiction within 120 days after lease execution in order to ensure an efficient and sustainable development process. The ACP should identify the lessee's agency liaison and the lessee's plan for regular interaction with government agencies, and those agencies must be invited to help draft the ACP. The lessee must provide a written summary of how it addressed agency comments.

The lessee must submit a survey plan at least 90 days before conducting any physical, biological or cultural resources survey, including the details and timelines sufficient for analysis by BOEM. The survey plan must be consistent with the FCP and NATCP and involve coordination with the US Coast Guard. The survey plan is deemed approved if BOEM does not respond within 30 calendar days. However, it may not be wise to assume deemed approval if the fisheries survey could result in a "take" of any endangered species. The BOEM lease says "additional time should be allowed" in such cases.

The lessee's biological surveys must be / *continued page 36*

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coordinated with BOEM, the National Marine Fisheries Service and US Fish and Wildlife to determine whether interaction is expected with any endangered species.

An archeological survey must be done. It must include an archeological report by a qualified marine archaeologist and must be done in coordination with federally-recognized tribes. The report must include a statement that there was no impact on historical properties or a description of the nature and extent of any impacts.

The lessee must also do an avian and bat survey, monitor offshore movement and include bird and bat deterrent devices. It must report annually to BOEM on any dead or injured birds or bats discovered at the site.

Developers bidding for sites in federal offshore wind auctions commit to a time-consuming and expensive process.

The lessee must submit a plan for "contributing to the creation of a robust and resilient US-based offshore wind supply chain." This supply chain includes vessels, infrastructure, grid upgrades, component manufacturing, storage and laydown yards, docks and navigation equipment, refueling stations and R&D. The lessee must make an effort to involve diverse communities during all phases of contracting. It must send BOEM regular updates on its efforts in this area and a self-evaluation of how well it is doing. The New York Bight auction gave bidders credit in bids that promised to use equipment manufactured or assembled in the US, including nacelles, blades, towers, foundations, transition pieces, inter-array cables, export cables and offshore substations. If achieved, bidders would be given a 50% discount on rent under the BOEM lease for five years.

The lessee must submit a progress report every six months during the initial five-year site assessment term. The progress reports must list interested parties with whom the lessee has engaged, what it is doing to mitigate any adverse impacts on those parties and what feedback it received from them.

Failure to follow all of the reporting requirements could delay project development or lead to a suspension of the lessee's operations by BOEM.

Other Issues

The COP should include a request for any easements reasonably required by the lessee for full enjoyment of the lease. BOEM will approve any easements it agrees are necessary without further competition.

The lessee must develop two common lines of orientation with the holder of any adjacent BOEM lease area. These are two straight channels for ships and helicopters to pass between adjacent projects. If the lessee is unable to coordinate, then there must be at least a one nautical mile setback from the adjacent area.

The lessee's operations may not be conducted in any manner as determined by BOEM that unreasonably interferes with any other lease or that could harm the environment, create a hazardous or unsafe condition or adversely affect any historic or cultural sites, structures or objects.

Development of an offshore wind farm takes several years after bid award and requires significant capital outlays before the first dollars of revenue are received.

It will be at least eight years after the Vineyard Wind project was awarded a lease (BOEM Lease OCS-A-0501) before it will start commercial operation.

A substantial bid deposit is required ($5 million for the New York Bight auction), and the entire bid amount must be paid within 10 business days after the award.

The first year of rent must be paid within 45 days after the lessee receives the lease for execution. The lessee must post $100,000 in financial assurance before lease issuance, additional security before SAP approval in an amount estimated by BOEM to meet all "accrued obligations," with a possible increase in the amount before COP approval, and a decommissioning bond by the start of construction. The financial assurance amounts are subject to adjustment for increasing or decreasing obligations at BOEM's discretion. These obligations are in addition to costs to prepare required surveys, develop and submit the SAP and COP and coordinate with stakeholders, and equipment supply and construction costs.

The lease includes a typical broad indemnity for any damage caused by the lessee, its employees or subcontractors.

However, it goes beyond that to make the lessee accountable for any damage caused by the US government in connection with any identified military command headquarters, including for any act or omission or negligence of the United States, its contractors, officers, agents or employees. This indemnity obligation overrides the lessee's limitation of liability contained in the lease and any directly contradictory lease provisions.

A requirement to indemnify a party for the party's own negligence is is unenforceable as against public policy in many jurisdictions.

BOEM may suspend activities, cancel the lease and impose penalties for any failure to comply with the submerged lands act, the SAP, COP or the terms of the lease.

It also retains the right to suspend any lessee activities due to national security concerns.

It can also cancel the lease if it determines that the lessee's activities could harm or damage life (including aquatic life), property, minerals or the environment.

The lease can be terminated only after the lease has already been suspended on account of the condition for five or more years. It can be terminated more quickly after a hearing that concludes the condition will not dissipate or if the government concludes the advantages of cancellation outweigh the benefits from continuing the lease. BOEM is not required to provide compensation for any suspension, but is required to compensate the lessee for a termination for loss of anticipated net revenue or, if less, the net costs paid by the lessee under the lease. ◎

Environmental Update

Solar generating equipment withstood much of the wrath of the two hurricanes that struck Puerto Rico and Florida in September, providing advocates for the industry with reason to argue that renewables paired with battery storage are a reliable form of energy even in the face of natural disasters.

Hurricanes Fiona and Ian knocked out electricity to 2.7 million users in Florida and to the three million residents of Puerto Rico. While causing widespread flooding, knocking out electricity supplied by power lines and washing away bridges and roads, solar panels and batteries reportedly performed well during the storms.

Media reports suggest that the grid bounced back faster than under past hurricanes not only because of recent efforts to bury power lines and otherwise harden power networks in Florida, but also because of the large number of rooftop systems coupled with batteries that have been installed in both Florida and Puerto Rico.

Electric Cars

More electric cars are expected to be sold in China than in the rest of the world combined in 2022: somewhere in the neighborhood of six million vehicles.

China's domestic electric vehicle market has expanded rapidly in the last decade, with the percentage of new all-electric or hybrid vehicles sold growing from about 5% of domestic Chinese sales in 2018 to more than 25% expected in 2022.

Approximately 300 Chinese companies now manufacture electric vehicles, or EVs, though they face fierce competitive infighting, and the market floor is strewn with many losers. While Tesla remains the world's single largest manufacturer in terms of global market, half of the world's 10 best-selling EV brands are Chinese.

To match the boom in Chinese production and domestic sales, availability of charging stations has been growing apace. There are now about four million charging units in China, about twice as many as there were just a year ago.

To be sure, the maturity of China's EV production, buildout of supportive infrastructure and now-thriving domestic sales market were achieved through more than a decade of long-term investments, financial subsidies and infrastructure spending, all driven by top-down government direction and planning.

Environmental Update

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While built on government subsidies, China's current car market now appears close to the point where electric vehicles can compete directly with gas-powered vehicles on price, even as government support is reduced.

By comparison, the US market for manufacturing EVs and building the supporting infrastructure has been starved of game-changing investment over the same decade in which the Chinese market has thrived. Many EV models have waiting lists and cost more than gas-fired alternatives.

While growing quickly, sales of EVs in the United States only recently passed the 5% threshold, a vastly smaller number both in the number of vehicles sold and as a percentage of domestic auto sales. US domestic sales went from a little more than 300,000 in 2020 to more than 600,000 in 2021.

The Inflation Reduction Act, signed into law in August, is a needle-moving investment that will inject hundreds of billions of dollars into both clean energy and electric vehicle incentives and programs. That said, the needle will probably move slowly.

In the absence of further legislative incentives, the factors that will drive the US market are likely to be high gas prices, climate concerns, price reductions from eventual increases in production and availability, and US manufacturers not wanting to lose out to advances by foreign competitors in an area of obvious future industrial importance.

The Inflation Reduction Act will clearly benefit the US EV industry, but it is less focused on increasing the number of EVs bought in the US in the near term than it is on slowly building up a comparatively embryonic US EV industry.

The Inflation Reduction Act expands tax credits for those buying a limited range of qualifying new EVs. Credits on models that meet the legislative conditions are capped at $7,500. The IRA will also provide a new tax credit of $4,000 toward the purchase of used electric cars after 2023, with sales subject to various other qualifying conditions. Importantly, and in contrast to previously existing programs, the IRA allows tax credits to be claimed at the time and point of sale starting in 2024, instead of when buyers file tax returns. Dealerships will be able to accept transfer of a buyers' tax credits in exchange for an equivalent discount on the car purchase. While leases do not qualify since the manufacturer receives the tax credit, some dealers may be willing to pass on the savings by reducing monthly payments.

Tax credits can only be claimed on new models that meet specific "made in America" qualifications. The goal is to build the industry here through tax credit-driven sales, protecting the US industry by not offering benefits to buy autos made in other countries.

The IRA imposes US-centric conditions for qualifying. These include minimums for US content in battery production as well as geographic requirements for manufacturing and assembly.

The conditions become tougher over time.

The 10-year time frame for EV credits provides some much-needed stability to the US market. The EV tax credits will remain available for vehicles placed in service by the end of 2032.

Some automakers criticized the IRA because a majority of EVs available in the US currently do not qualify for tax credits. The sourcing requirements are also likely to lead to higher vehicle prices.

To qualify for the $7,500 tax credit, final assembly must occur in North America and a certain percentage of materials used in the battery must have been extracted, processed, manufactured or assembled in the US or certain US-allied nations. Cars that meet only one of the requirements may be eligible for a half credit of $3,750.

Starting in 2023, tax credits can be claimed on electric vans, SUVs, and pickup trucks only if the manufacturer's suggested retail price is $80,000 or less, and to electric sedans, coupes, wagons and convertibles with manufacturer's suggested retail prices of $55,000 or less. The IRS also puts a $125,000 annual income limit on single tax filers and a $300,000 limit on joint filers.

For previously-owned EVs, buyers can claim a credit of up to the lesser of either $4,000 or 30% of the sale price. A tax credit can only be claimed on the first resale of a used vehicle. There are restrictions on sales between related parties. Tax credits cannot be claimed on used vehicles sold for more than $25,000. They may only be claimed by buyers with adjusted gross incomes of $75,000 or less ($150,000 for married couples filing jointly).

In addition to buyer incentives, the IRA also creates a new advanced manufacturing production credit for the US production of components used in solar, wind and battery storage and for mining about 50 critical minerals. The IRA also authorizes $10 billion in tax credits for building new factories or re-equipping existing factories to make equipment for the green economy and another $2 billion in grants to revamp existing factories.

Forever Chemicals

The US Environmental Protection Agency published proposed in September to designate two "forever chemicals" as hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act, known as CERCLA or the Superfund law.

The large number of solar rooftop systems coupled with batteries helped Florida and Puerto Rico weather two major hurricanes in September.

The two chemicals are perfluorooctanoic acid (PFOA) and perfluorooctane sulfonate (PFOS), including their salts and structural isomers. Both have largely been phased out of current use, but both were used commonly in the past and their legacy in the environment could be considerable.

PFOA and PFOS belong to a class of chemicals called perfluoroalkyl and polyfluoroalkyl compounds, or PFAS (pronounced PeeFAS). The class of chemicals is sometimes referred to as "forever chemicals" because they build up in the environment over time and are difficult to break down even with the passage of time.

PFAS are a broad group of fluorinated chemicals that are added to a wide variety of consumer products to make them non-stick, waterproof, stain-resistant and fire-resistant.

Consumer products containing PFAS include carpets and upholstery, waterproof apparel, floor waxes, non-stick cookware, camping gear, fast-food wrappers, cleaners, dental floss and firefighting foams for putting out intense fuel fires. PFOA have been used in non-stick cookware, flame repellants and cosmetics. PFOS have been used in water- and stain-resistant products.

Until now, no PFAS have been regulated as "hazardous" under CERCLA.

The proposed designation of PFOA and PFOS as hazardous would trigger regulation under CERCLA and lead eventually to investigations and enforcement by EPA at sites across the country.

This could not only trigger the listing of new Superfund sites contaminated by PFOA and PFOS, but could also lead to reevaluation of remedies at active Superfund sites and the reopening of investigations at sites that had achieved regulatory closure but where these previously-unregulated chemicals were released into the environment and not remediated.

This could mean significant new cleanup costs for responsible parties.

Responsible parties will have to report releases of PFOA and PFOS that meet or exceed the reportable quantity eventually assigned to these substances.

EPA is collecting comments on the proposal through November 7. It may also ask for comments on designating other PFAS as hazardous substances.

EPA is likely to regulate in piecemeal fashion. PFOA and PFOS are two of the most widely studied PFAS, but EPA has identified 24 other classes of PFAS that require study before concluding how toxic they are. It will take time for studies to inform any new regulation, if needed.

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broader regulation, many states have been actively regulating PFAS on a wider scale without waiting for federal action.

Companies likely to be affected by the proposed hazardous substance designation include PFOA and PFOS manufacturers and processors, manufacturers of products containing the chemicals, downstream users and waste management and wastewater treatment facilities, including landfills.

PFAS have been found in drinking water in many parts of the country. Whatever the sources, the Centers for Disease Control and Prevention has found PFAS in the blood of nearly all people tested, with levels varying widely.

— contributed by Andrew Skroback in New York

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