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Energy Transition Report

PROXIMO

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Can the US power sector deliver on carbon reduction goals?

The US power sector has been tasked with achieving net zero carbon by 2035 – 15 years ahead of the rest of the US economy. But does it have the regulatory certainty to inspire power investors to make the capital-intensive changes required? By Lee Van Atta, Vice President Energy & Infrastructure Consulting, Leidos.

In April 2021, President Biden announced a number of goals related to carbon reduction, including an economy-wide goal of a 50% to 52% reduction in greenhouse gas emissions from 2005 levels by 2030, a goal for the US power sector to reach zero net carbon by 2035, and a goal for the US economy to reach net zero carbon by 2050.

The calendar sequence of these goals signals that the US power sector is expected to do much of the heavy lifting for achieving carbon reduction. The strategy involves electrifying to the fullest extent possible the sectors of the US economy most dependent on carbon-emitting fuels (such as the transportation sector) while at the same time moving to renewables and other zero-carbon sources for power generation – in short, US power transition is the foundation stone for all other transition.

That the plan relies so heavily on US power sector transition is both a strength and a weakness: a strength in that the US power generation sector is already on a path toward decarbonisation (largely as a result of market forces), and a weakness because federal policies focused on the power sector have tended to increase regulatory uncertainty, which deters the very investments required to realise the carbon reduction goals.

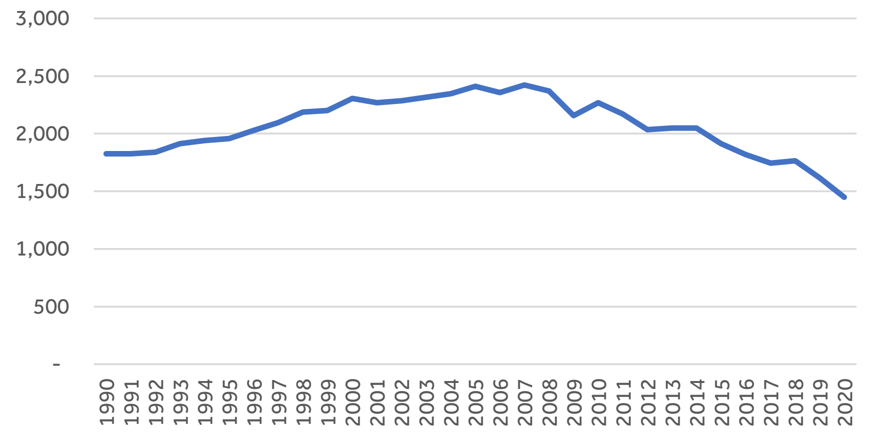
The stakes involved are incredibly high – not only in terms of mitigating climate change but for simply keeping the lights on. As highlighted by Winter Storm Uri and the resulting ERCOT electricity blackout in February 2021 and the wildfires and heat storm which led to California's "rolling blackouts" during summer 2020, the climate crisis will produce extreme weather events that will invariably stress the reliability of the US power grid. Critical investments are needed not only to transition toward a net zero carbon US power sector but to improve the resiliency of the US power grid.

The rapid decarbonisation of the US power grid

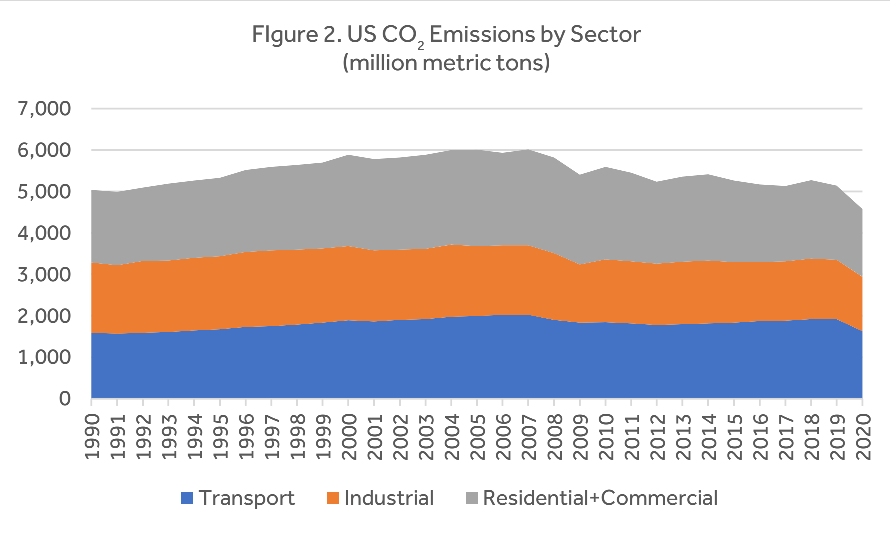
For much of the last century, the US power sector was on a much different path in terms of carbon emissions as economic growth and increasing power consumption drove higher levels of CO_2 emissions. As shown in Figure 1, US power sector CO_2 emissions increased over 30% from approximately 1,800 million metric tons (MMT) in 1990 to over 2,400 MMT in 2007. Since 2007, US power sector CO_2 emissions have trended down and were approximately 1,600 MMT in 2019. Emissions during 2020 fell below 1,500 MMT, which reflected the impact of the Covid-19 pandemic, and estimates for 2021 levels are comparable to 2019 levels which reflects the strong rebound in the economy and relatively high natural gas prices supporting more coal-fired power generation. Even with that rebound expected in the near term, the US power sector has produced more than a 25% reduction in CO_2 emissions since 2005.

Figure 2 illustrates that total US CO_2 emissions show a similar trend. Emissions peaked in 2007 at just over 6,000 MMT after generally rising from the 1990 level of approximately 5,000 MMT. After 2007, emissions trended down with CO_2 emissions in 2019 under 5,200 MMT. Looking at just the transportation sector, it is important to note that CO_2 emissions were actually trending up prior to the pandemic year of 2020. Over 80% of transportation sector CO_2 emissions are from motor gasoline and diesel, which is why the push towards electric vehicles is critical to reaching the Biden Administration's carbon reduction goals assuming the grid can be further decarbonised. In addition,

Figure 1. US Electricity Generation CO_2 Emissions (million metric tons)



Source: US Energy Information Administration (EIA)



Source: EIA

over two-thirds of CO_2 emissions from the residential and commercial sector and approximately one-third of CO_2 emissions from the industrial sector are from purchased electricity. Decarbonising the power grid will directly affect these sectors given that large portions of emissions from these sectors are from purchased electricity so reduction in CO_2 emissions related to electricity generation will pass directly through to these sectors. In addition, accelerating decarbonisation of the power grid will also pass directly to the portions of those sectors that are associated with purchased electricity.

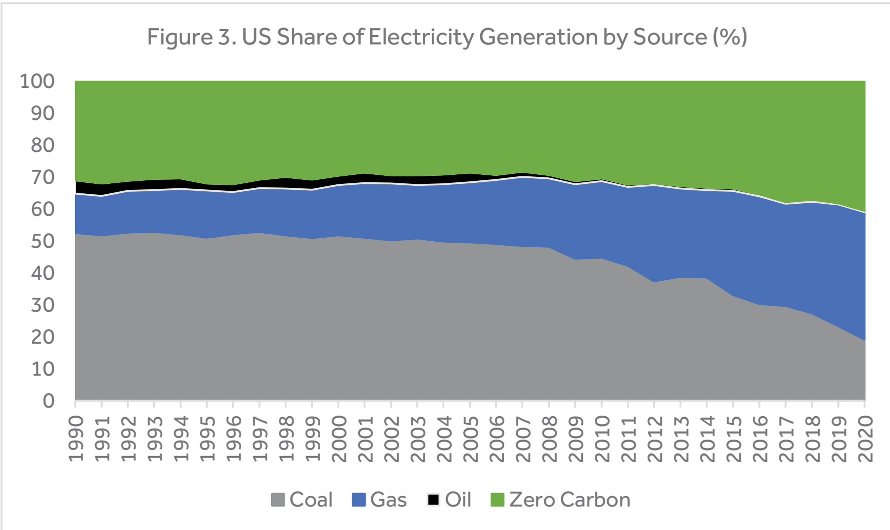
This becomes more important when considering the uncertain timing involved with electrifying the remaining portion of the residential and commercial sector whose emissions are not currently from purchased electricity. Time is also likely to be a factor in the industrial sector, which is seen as having segments that may not be feasible to electrify. Innovations such as green hydrogen and other renewable fuels are often touted as being key to the sector's decarbonisation but face challenges in reaching commercial scale. These renewable fuel innovations may also be critical for some segments of the transport sector where limitations on use of batteries may make electrification infeasible.

As highlighted in Figure 3, one of the main drivers for the reduction in US power sector CO_2 emissions since 2007 is the dramatic increase in the role of natural gas. From 2007 to 2020, the share of US electricity generation from natural gas increased from around 22% to 40% while coal's share declined from 48.5% to 19%. This near flip-flop in the role of natural gas and coal in electricity generation produced substantial benefits in CO_2 emissions because use of natural gas in power generation in a modern combined-cycle plant produces less than half the carbon emissions on a per MWh basis when compared to a typical coal-fired plant. [1]

This switch from coal to natural gas was driven largely by market forces and the massive increase in shale gas production from 1.3 trillion cubic feet (TCF) in 2007 to over 26 TCF in 2020. This gusher of new, low-cost natural gas supplies spurred power generation demand and drove a boom in combined-cycle gas turbine (CCGT) power generation development, particularly in PJM whose footprint largely overlaps some of the most productive shale gas plays in the country. Despite the surge in demand from the power generation sector, natural gas market prices remained relatively low over the past decade, which enabled the growing number of CCGTs to outcompete older coal-fired plants on the dispatch stack in PJM and other competitive US power markets.

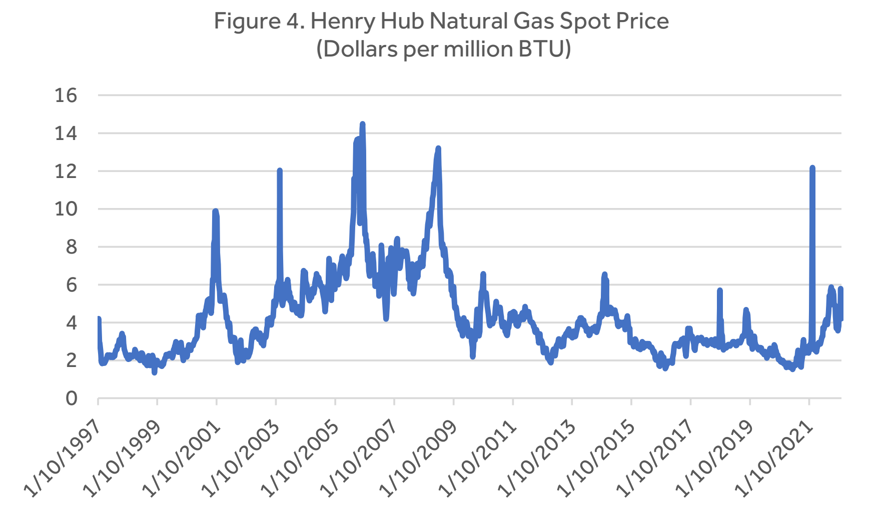
As shown in Figure 4, from 2001 to 2010, the US natural gas price at Henry Hub (a key trading point in Louisiana) averaged approximately \$5.8/MMBtu, and the price spiked above \$10/MMBtu numerous times in 2005 and 2008. Once the shale gas revolution took hold starting in 2011, Henry Hub prices averaged approximately \$3/MMBtu and prices have spiked far less frequently. Natural gas prices have been remarkably rangebound between \$2/MMBtu and \$4/MMBtu for the past decade. The only reoccurrence of Henry Hub natural gas prices above \$10/MMBtu occurred in February 2021, which saw large amounts of production freeze-offs during Winter Storm Uri that led to power outages in Texas. Since that event, US natural gas production recovered but Henry Hub spot prices over the past 12 months have averaged above \$4/MMBtu.

Although the recovery in natural gas prices over the past 12 months has supported higher coal-fired power generation, a higher price for natural gas also supports growth in renewables. In fact, the amount of wind and solar capacity additions has been astounding over the past 12 months although the reasons for this are long in the making



Source: EIA

[1] 784 pounds CO_2 for Gas CCGT (7,000 Btu/kWh heat rate multiplied by carbon content of natural gas of 112 lbs. per MMBtu) compared to 2,000 pounds CO_2 for Coal Steam Turbine (10,000 Btu/kWh heat rate multiplied by carbon content of 200 lbs. per MMBtu)

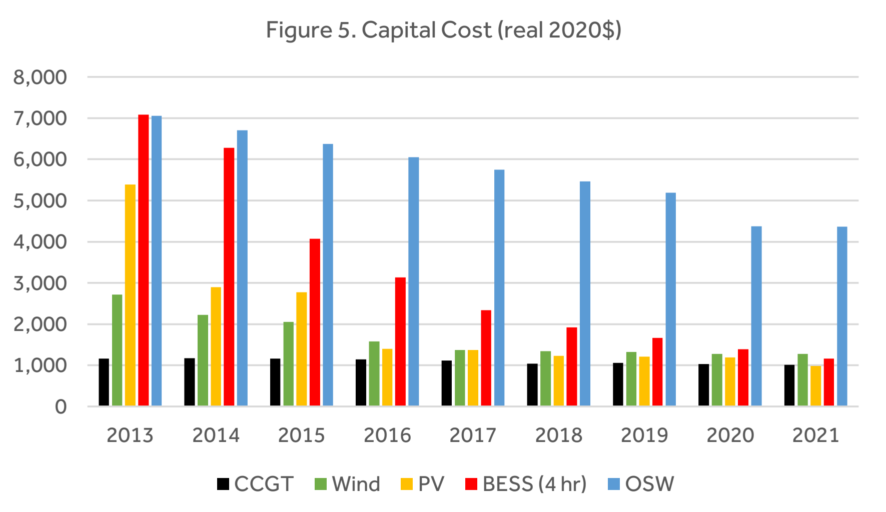


Source: EIA

and not a result of the sudden uptick in the price of natural gas.

Stepping back, the US share of electric generation from zero carbon sources hovered around 30% with little change from 1990 to 2010. Over the past decade, the share of zero- carbon sources rose steadily from 30.4% in 2010 to 40.6% in 2020. The increase in zero carbon sourced electric generation was driven by wind additions during the first half of the decade as the capital cost for new wind capacity became more competitive. As shown in Figure 5 ,utility-scale solar photovoltaic (PV) power plants were still relatively expensive compared to wind or CCGT prior to 2013 but capital costs for PV dropped significantly from 2013 to 2016 leading to a surge of development. In 2020, for the first time in the US more wind and more PV capacity was added than natural gas-fired capacity (11.6 GW wind, 7.75 GW PV, 5.9 GW natural gas-fired). The cost competitiveness of wind and PV was further supported by potential tax subsidies, namely the Production Tax Credit (PTC) and Investment Tax Credit (ITC). Even before consideration of the PTC/ITC subsidies, the capital cost of wind and PV had become competitive if not cheaper in some parts of the US than CCGT. Even more striking are the dramatic capital cost declines in battery energy storage systems (BESS) over the past five years leading to the capital cost of a 4-hour duration BESS project to become competitive with CCGT. Estimates from the EIA indicate that by 2021, the capital cost for a 4-hour duration BESS, utility-scale PV, and onshore wind had declined to approximately $1,000 to $1,300 per kW, which makes these resources highly competitive with CCGT. Further technology-driven performance improvements and cost reductions are expected going forward that will continue to make BESS, utility-scale PV, and onshore wind more competitive even if PTC/ITC tax subsidies decline as currently set in federal law.

While capital cost estimates for offshore wind (OSW) have come down in recent years, OSW remains relatively expensive. Not surprisingly, OSW projects are proceeding based on additional subsidies (e.g., Offshore Renewables Energy Credits) and other out-of-market contractual support.



Source: EIA AEO Technical Assumptions, various years

Policymakers face carbon conundrum

The decline in coal-fired power generation and rise of renewables portends well for continued decarbonisation of the US power grid but Leidos' analysis indicates that reaching the Biden Administration's goals will require additional policy changes. As presented in Figure 6, modeling the current status quo results in meaningful but inadequate levels of carbon reduction. In Leidos' projections of the US power sector, when we model the current set of federal and state policies, we see rapid growth in renewable generation but also some regions where additional natural gas-fired capacity is added. In addition, while we project a sizeable portion of the coal-fired generation fleet will retire over the next five years, there are areas in the Midwest and Southeast US that we project will continue to have a meaningful level of coal-fired power generation well into the 2030s. As a result, under these 'status quo' assumptions, US power sector CO_2 emissions continue to decline but are nearly 1,000 MMT in 2035 compared to the Biden Administration's goal of net zero carbon by that year.

To achieve the net zero US power sector policy goal, the Biden Administration was counting on the Build Back Better legislation and specifically the Clean Energy Performance Program that would have set a clean energy standard for electricity generation. The legislation passed the House of Representatives on November 19, 2021, but did not find a way through the closely divided Senate. While the Biden Administration continues to strategize on various options to enact at least portions of its climate change agenda, significant new federal policies and programs appear unlikely given persistent political division.

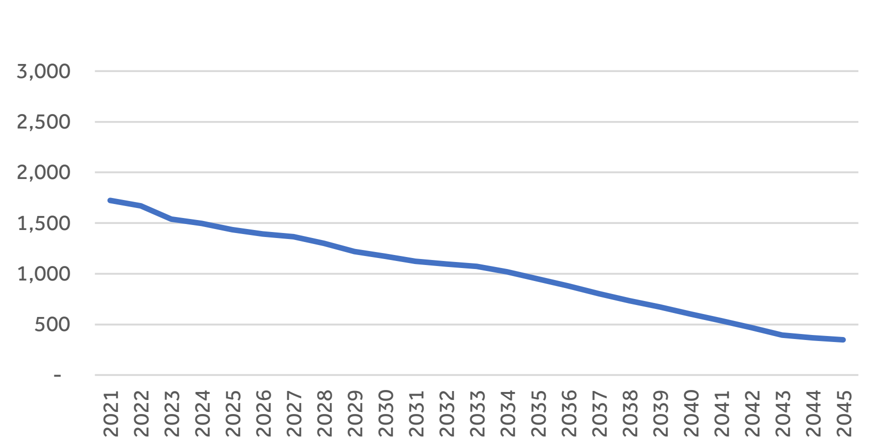
New legislation appears more likely around areas of past bipartisan success such as extensions and improvements of the existing PTC/ITC tax subsidies for wind and solar and potentially expanding those tax subsidies to energy storage and other technologies such as carbon capture and sequestration. However, it remains highly uncertain what, if any, new legislation will be enacted even in these areas where there appears to be broad support.

This uncertainty is not a new condition for the utilities and independent power companies operating in the US power sector, but it has long been a refrain that decisionmakers at these entities desire more certainty especially with regards to the regulatory environment. The US power generation, transmission, and distribution system is comprised of highly capital-intensive and long-lived assets. Making investment decisions in these assets requires a level of certainty in the regulatory environment.

And so, this brings us back to the weakness in placing the US power sector at the center of the carbon reduction strategy. Efforts to implement these policies at the federal level tend to increase regulatory uncertainty which is counterproductive to bringing forth the required investment. A 'case' in point is that the Obama Administration's never-implemented Clean Power Plan is still being litigated in front of the US Supreme Court (the case in question being *West Virginia v. Environmental Protection Agency*).

Paradoxically, uncertainty is only expected to increase as federal policymakers focus more attention on the US power sector. Overcoming this growing uncertainty will be yet another challenge for investors focused on the energy transition.

Figure 6. Leidos Status Quo Outlook: US Power Sector CO_2 Emissions (million metric tons)



Source: Leidos

Mr. Van Atta is a Vice President in the Leidos Energy Infrastructure & Consulting Division. He has more than 25 years of energy market consulting experience focused on energy infrastructure development, acquisition, and financing. He has supported over 30 GW of power asset development and financing in North America.

Can shrinking hydrogen's cost gap increase dealflow?

A look at how hydrogen costs could decrease and what that might mean for the supply of bankable projects. By Xi Chen, MPA, and Jim Guidera, adjunct professor, Columbia University.

Clean hydrogen is widely touted as a solution for the hard-to-decarbonize sectors: a feedstock for chemical, steel, cement, and fertilizer production, a fuel for marine and heavy transport, an energy storage medium and load-following source to support variable wind and solar generation. Investors and lenders seem ready finance hydrogen-linked projects, but few bankable deals have come to market so far.

The main obstacle to the broad adoption of clean hydrogen is its high cost relative to the traditional fossil fuels and the chemical feedstocks derived from fossil fuels. The cost-gap between clean hydrogen and traditional fossil fuels was the subject of recent research by a team of graduate students at Columbia's School for International and Public Affairs (SIPA): Abdulaziz Alhumud, Sho Aihara, Sindhura Chakravarty, Xi Chen, Courtney Jacobs, Andres Moncada-Lopez, Xiaoming Zhong. Their study was sponsored by Credit Agricole CIB, which has made financing the energy transition a priority. This SIPA group developed metrics for measuring the present cost gap and a forecast that bankable hydrogen deals will appear in the market prompted by the shrinking cost gap between hydrogen and fossil fuels.

One caveat: The cost gap between clean hydrogen and fossil fuels in energy import markets could shrink more quickly than expected. Finding alternatives to Russian gas supply may cause fossil fuel prices to remain high over the long term, contributing to more hydrogen demand in the European market especially. Along with assisting the energy transition, increased hydrogen use may become a security measure.

Clean hydrogen costs

Carbon-free hydrogen is manufactured either using traditional processes that rely on a coal or natural gas feedstock, with a carbon-capture and storage process added (blue hydrogen) or by employing renewable electricity and water in an electrolyzer process to separate hydrogen (green hydrogen). The cost estimates for producing blue hydrogen (estimated at $1.5-2.5 per kg) are marginally higher than traditional grey hydrogen production costs as the carbon capture and storage costs are marginally incremental to the traditional processes. The estimates of producing green hydrogen presently range to much higher levels: $2.14-6.39 per kg (see Figure 1 below), according to a model developed by the SIPA group to forecast the levelized cost of green hydrogen (LCOH).

The major cost drivers for green hydrogen manufacturing are the cost of electricity from renewable sources and the recovery of the electyrolyzer CAPEX – which can represent a high embedded capital cost if the electrolyzers are operating at low utilization rates. Since solar and wind generation sources operate when the sun is up and the wind is blowing the utilization rate of a manufacturing process fed by solar or wind will be limited.

Without being powered by a fully decarbonized grid, nuclear or hydro, a green hydrogen manufacturing process powered by solar or wind or a combination of the two could be expected to operate at a utilization rate matching the capacity factor of the renewable energy source. While the best solar operates in the range of 30% and the best wind sources might operate at 60% capacity, a combined wind and solar electricity source might allow the green hydrogen manufacturing process to achieve a utilization rate above 60%. The green hydrogen production costs at the very low end of the range, starting from $2.14/kg will only be found in those countries with the best wind and solar resources.

Alkaline (20 MW)

		Electrolyzer Utilization				
Electricity Cost ($/MWh)	$/kg	60%	50%	40%	30%	20%
	$20	$2.14	$2.37	$2.71	$3.27	$4.40
	$30	$2.64	$2.87	$3.20	$3.77	$4.89
	$40	$3.14	$3.36	$3.70	$4.27	$5.39
	$50	$3.64	$3.86	$4.20	$4.76	$5.89
	$60	$4.13	$4.36	$4.70	$5.26	$6.39

Figure 1 LCOH Cost Comparison with Alkaline Electrolyzer

Measuring the cost gap between clean hydrogen and fossil fuels

Figure 2 below converts the price ranges for blue and green hydrogen into an energy cost metric equivalent to market costs for natural gas and diesel fuel in the target markets of Europe and Japan in February 2022. Hydrogen (normally priced at $ per kg), natural gas (normally priced at $ per million Btu, or mmbtu), and diesel fuel (normally priced at $per liter) are all compared according to a common energy unit: gigajoules ($ per GJ). At a low heat value of 120 MJ per kg, the SIPA model estimates green hydrogen at LCOH prices ranging from $2.14 per kg increasing up to $6.39 per kg and higher (from table 1 depending on various electricity costs and utilization) has an equivalent energy value range of $17 per GJ to $50 per GJ. The blue hydrogen with a price of between $1.5 and $2.5 per kg is also converted into their equivalent GJ value.

The lowest production costs for green hydrogen would be in countries with the most favorable wind and solar resources like Saudi Arabia and Chile, while lower cost blue hydrogen would come from countries with cheap gas or coal feedstock like the US or Australia. The cost estimates of importing clean hydrogen to target markets like Japan and Europe vary widely from between $0.6 and $3.5 per kg, so for the comparison in Figure 2, a $2 per kg average has been added to arrive at a cost-range after transportation [2]

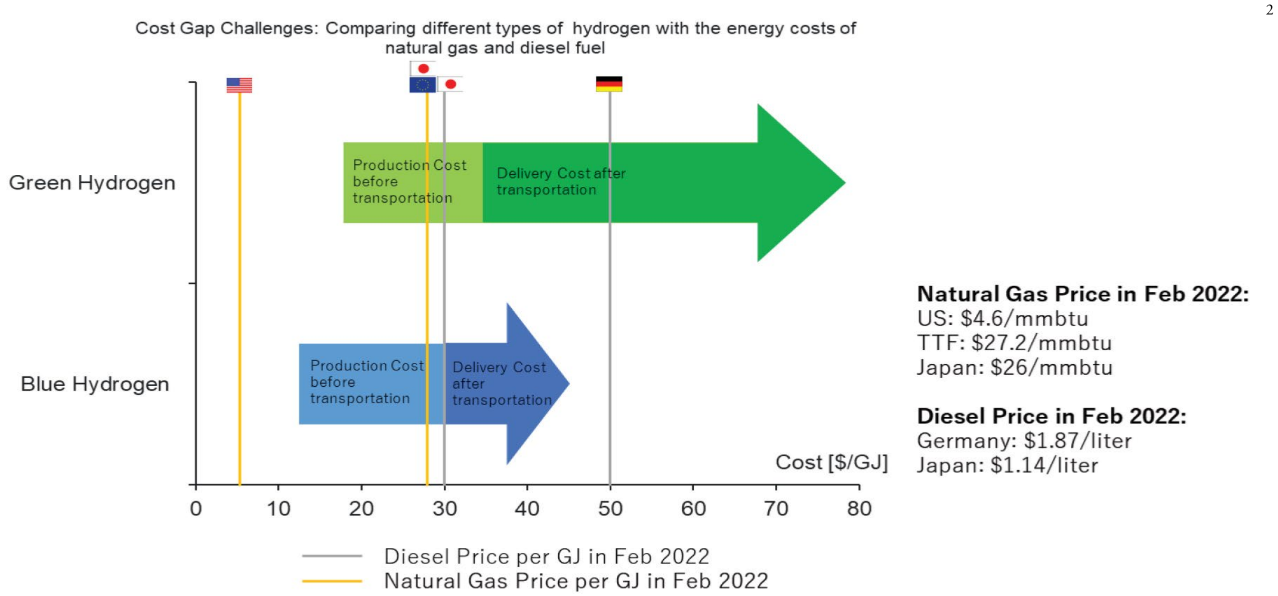
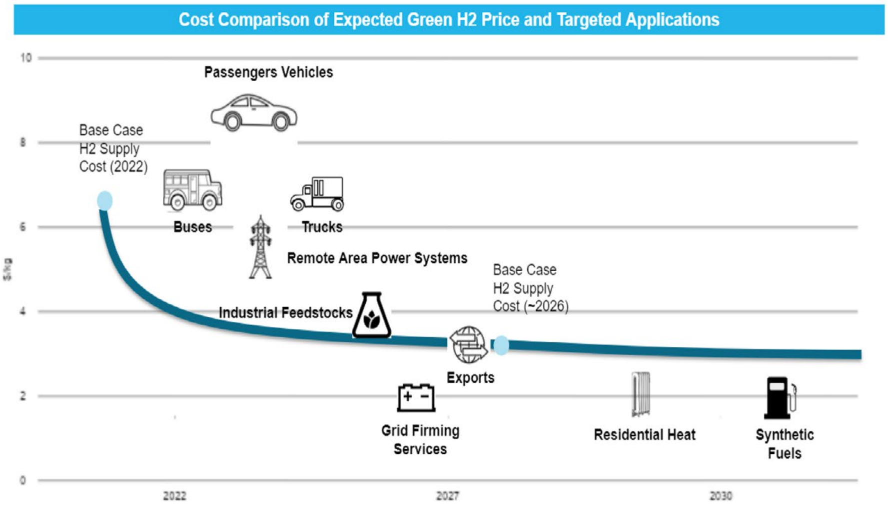


Figure 2 Comparison of Hydrogen Costs with Fuel Alternatives

[2] Natural price is converted at 1 mmbtu=1.05GJ, diesel price is converted at 1 liter=38MJ, hydrogen price is converted at low heat value of 120 MJ per kg



Source: Leidos

to the target markets (the darker-shaded end of the hydrogen cost bars).

These price ranges are compared with the average market costs for natural gas and diesel fuel converted to GJs in Japan, Europe and Germany in February 20212. Figure 2 shows how a theoretical estimate for the delivered green hydrogen priced at the lower end of the cost range ($4.14 per kg, or $34 per GJ) could compete with the price of diesel in Germany as it prevailed in February 2022 ($ 1.87 per litre; $49 per GJ). This estimate for delivered green hydrogen would be only slightly above the February 2022 diesel price in Japan and the natural gas prices in Europe and Japan.

Energy prices in February 2022 were relatively high compared with pre-2020 winters, reflecting the tight energy supplies in 2021-22 and the lead-up to war in Ukraine. While prevailing global security concerns make it hard to label what would be normalised prices for competing fossil fuels, the Figure 2 still implies the possibility for green hydrogen to close the cost gap with fossil fuels in targeted markets.

Factors to reduce clean hydrogen costs

The hydrogen industry is growing fast, with rapid improvements in driving potential cost reductions. With the help of government policies and incentives, the cost gaps between hydrogen and fossil fuels could be reduced or even eliminated in the coming years. For green hydrogen the most important factors in production costs are the costs for renewable electricity and the capital cost for electrolyzers.

Alkaline and PEM (polymer electrolyte membrane) are the two dominant technologies in the electrolyzer market. Alkaline is the more mature and lower cost technology ($600 - $1,100 per kW); PEM is more expensive ($800-$1270 per kW) but is considered more suited to renewable power sources. The global installation of electrolysis capacity has been trending upwards over the past five years, with many countries setting incremental installed electrolyzer targets for 2030. As global demand for electrolyzers increases, market participants expect the effects of higher scales and higher skills to drive rapid price reductions, as observed in solar photovoltaic technology during the 2010s. Industry experts are forecasting that electrolyzer cost reduction of 50%–70% are achievable through deployment acceleration and technological innovation.

Over the past decade, the renewable power sources have experienced remarkable cost reductions. The global average levelized cost of energy (LCOE) for solar PV has decreased 85%, from $0.381 per kWh in 2010 to $0.057 in 2020, with a more than 93% reduction in installation costs. Countries such as Spain, Chile, and Saudi Arabia have among the best solar resources in terms of irradiance, capacity factors, and installation and transmission costs. They also have sufficient wind resources for combined wind and solar, to achieve high combined capacity factors. Numerous green hydrogen export projects are under development in these countries.

Hydrogen dealflow driven by economics

Bankable deals linked to hydrogen are likely to be driven by the evolving trends in clean hydrogen costs. Green hydrogen production at costs in the $2 per kg range from the best solar and wind resources, increased by transport costs to the $4 per kg range when delivered to high-priced markets, is in a better position to compete with and displace expensive fuels like gasoline and diesel for buses and heavy-haul vehicles in the high-priced markets like Europe and Germany, or for power generation in remote markets.

Blue and green hydrogen costs would need to decline to between $2.50 and $3 per kg delivered to market to be competitive for use as an industrial feedstock or to provide grid-firming services during high demand periods. Clean hydrogen pricing would need to drop further in the years beyond 2030 to displace natural gas for home heating and gasoline for vehicles in broad retail markets. The figure below illustrates a possible path for hydrogen applications becoming economic among the different sectors over the long term.

In 2022 the largest green hydrogen project financing - for the $5 billion Helios project – is near market. Air Products, AWCA Power International and Neom are the sponsors of Helios, which is located in Saudi Arabia would convert green hydrogen to ammonia for export to European markets as fuel for buses and trucks. In 2021 Meridiam, Hydrogene de France and SARA closed a more modest $150 million project financing for the CEOG hydrogen generation and storage project, which is designed to displace diesel generation in French Guyana.

Multiple hydrogen export projects are under development in countries with favourable clean hydrogen resources like Spain, Chile, Australia; these are likely to come forward in 2022 and beyond to target diesel displacement in high priced markets like Europe and Japan. As noted earlier, the urgency of energy security policy may join with decarbonization goals to especially accelerate hydrogen use in those markets that rely on imported LNG.

Navigating US laws that apply to carbon capture

The US government is supporting carbon capture sequestration, utilization and storage (CCUS) projects. Although there is no specific federal CCUS regulation in place, projects can still face hurdles from a variety of different environmental laws. By Lauren A. Bachtel, Philip K. Lau, Dale D. Smith, Eric R. Pogue, and Emily Gleichert, counsel at Mayer Brown.

Carbon capture, sequestration, utilization, and storage (CCUS) will be essential in meeting the Biden administration's net zero GHG emission goals. As the chair of the White House Council on Environmental Quality (CEQ) acknowledges: "to reach the President's ambitious domestic climate goal of net-zero emissions economy-wide by 2050, the United States will likely have to capture, transport, and permanently sequester significant quantities of carbon dioxide" (87 Fed. Reg. 8808 (Feb. 16, 2022)).

Congress and the Biden administration have taken actions to support CCUS deployment. With the bipartisan Infrastructure Investment and Jobs Act (IIJA), Congress signaled strong interest in accelerating CCUS as a national decarbonization strategy by providing billions of dollars of new investments to support the industry.

Building on this strategic commitment, CEQ recently issued new guidance on the responsible deployment of CCUS technologies, including direction on incorporation of environmental justice and equity considerations, meaningful public engagement and Tribal consultations, and support for union-job creating projects.

Additionally, the Environmental Protection Agency (EPA) is developing proposed rule revisions to improve transparency on CCUS activities, the Department of Energy (DOE) is committing $5 million for university training and research related to carbon management, and the Federal Permitting Improvement Steering Council is facilitating a collaborative CCUS project review among its member agencies.

Nonetheless, CCUS projects still face several regulatory obstacles in the United States. There are no CCUS-specific federal environmental laws or regulations, but instead the precise mix of environmental permits and reviews needed for a particular project must be determined by the project-specific details. Below we highlight some of the major federal environmental laws that may apply to CCUS projects.

National Environmental Policy Act (NEPA)

NEPA requires federal agencies undertaking a "major federal action" to evaluate the environmental effects of the action. The policy goals of NEPA are achieved through "'action-forcing' procedures that require that agencies take a 'hard look' at environmental consequences", (Robertson v. Methow Valley Citizens Council, 490 U.S. 332, 350 (1989)).

CCUS projects with a federal nexus (e.g., federally funded or occurring on federal lands) may trigger NEPA. CCUS projects in the United States may receive federal funding, whether they are in development or fully operational. NEPA is triggered if federal funding involves significant federal control or influence over the use of funds. However, CCUS projects with minimal federal funds and no agency control over the project's outcome are not subject to NEPA. DOE takes the lead on NEPA for many CCUS projects in the United States due to the agency's primary role in CCUS project funding.

Recently, the federal government has taken actions to facilitate NEPA reviews for CCUS projects. On February 16, 2022, the CEQ published in the Federal Register new interim guidance that the White House said is intended to "facilitate sound and transparent environmental reviews for CCUS projects." The guidance builds on CEQ's June 2021 CCUS report, and, among other things, it "encourages agencies to prepare publicly available life cycle analyses of carbon capture and utilization and carbon dioxide removal projects." Whether the guidance, which was open for public comment through April 18, 2022, creates efficiencies or delays is yet to be seen.

Importantly, CEQ's NEPA regulations are in flux. On April 19, 2022, CEQ published the first of two phases of rulemakings to reform and modernize its NEPA regulations. CEQ's first regulation, effective as of May 20, 2022, undoes some of the key changes put in place in 2020 under the former administration, authorising federal agencies to more broadly consider the effects of major federal projects.

CEQ has not clarified whether the revised regulations will require agencies to adjust current NEPA reviews but instead stated that "agencies have sufficient discretion to apply their existing NEPA procedures in a manner not inconsistent with CEQ's regulations." CEQ also noted that the "rule will not delay any projects or reviews underway and will not add time to the NEPA process."

So, at this point, it is unclear how CEQ's new NEPA regulations will impact future CCUS projects. Indeed, uncertainty abounds. While narrowly targeting certain key elements, CEQ's patchwork first phase regulation leaves other aspects of the 2020 regulation in place; the 2020 regulation remains the subject of pending litigation; and agencies have not yet announced any clear implementation policies going forward. CEQ's second, likely broader NEPA regulatory revision is expected later this year, which could further muddy the water.

Clean Water Act (CWA)

To protect the nation's waters, the CWA requires a National Pollutant Discharge Elimination System (NPDES) permit before any pollutant can be discharged from a point source into a water of the United States. CCUS projects will require NPDES permits to discharge process wastewater or stormwater associated with the projects. In addition, pursuant to Section 404 of the CWA, the Army Corps of Engineers issues permits for discharge of dredge or fill materials into jurisdictional waters. Section 404 requires a permit for any utility line crossing that requires the discharge of dredge or fill materials into US waters. This includes "any pipe or pipeline for the transportation of any gaseous, liquid, liquescent or slurry substance for any purpose." Therefore, a Section 404 permit (general or individual) may be required for a CCUS project or pipeline that is close to or crosses water or wetlands.

National Historic Preservation Act (NHPA)

The NHPA and its implementing regulations require federal agencies to consider the effects of their federal and federally assisted or licensed "undertakings" on historic properties, which is broadly defined. If the lead agency determines that a CCUS project is the type of activity that has the potential to effect historic properties, then it must consult with the appropriate State Historic Preservation Office, Tribal Historic Preservation Office, and any Indian tribe that attaches religious and cultural significance to identified historic properties.

Similar to NEPA, the obligations under the NHPA are generally procedural in nature and are aimed at consultation to avoid or mitigate impacts from the proposed projects.

Endangered Species Act (ESA)

The ESA is a substantive statute designed to protect from extinction species that are designated as threatened or endangered and their designated critical habitat. CCUS projects may require certain ESA consultations to review any potential impacts to protected species and their critical habitat.

If the project has a federal nexus, the ESA requires the lead federal agency to ensure that its actions are not likely to jeopardize the species or adversely modify its critical habitat. Section 7 of the ESA requires that the agency consult with the US Fish and Wildlife Service or the National Marine Fisheries Service (depending on the species impacted) to determine the impacts of the CCUS activity on protected species or their critical habitat.

If there is not a federal nexus, CCUS project proponents may be required to consult with the US Fish and Wildlife Service or the National Marine Fisheries Service under Section 10 of the ESA and may be required to develop a habitat conservation plan.

Clean Air Act (CAA)

Depending on their size and location, CCUS projects may have to obtain certain CAA permits. A CAA Title V operating permit is required for a "major source," which has actual or potential emissions at or above the major source threshold for certain air pollutants.

The Title V operating permit generally does not add new requirements for the facility but instead contains emission limitations and other conditions to assure compliance with all CAA requirements, and it requires that certain procedural requirements be followed.

Prevention of Significant Deterioration (PSD) permits are required for new major stationary sources or major modifications for pollutants if the project is located in attainment or unclassifiable with the National Ambient Air Quality Standards (NAAQS).

Nonattainment NSR (NNSR) permits

are required for new major stationary sources or major modifications in areas that do not meet one or more of the NAAQS. A minor NSR permit is required for any new or modified source of air pollutant that emits lower than the major NSR emission thresholds and, thus, is not subject to PSD or NNSR permitting requirements. Carbon dioxide leakage from a CCUS project could result in violations of its applicable CAA permits.

Underground Injection Control Act

The Safe Drinking Water Act requires the EPA to establish rules to protect underground sources of drinking water. In furtherance of this mandate, EPA developed the Underground Injection Control (UIC) program, which sets rules for operating underground injection wells.

EPA has promulgated regulations and established minimum federal requirements for six classes of injection wells. CCUS projects fall within two primary UIC well classes: (1) Class II wells, which are those used exclusively to inject fluids that are associated with oil and natural gas production (storage of carbon dioxide is generally incidental to such operations); and (2) Class VI wells, which are those used to inject carbon dioxide into deep geologic formations for the purpose of storing carbon dioxide. EPA has developed Class VI program rules to address the permanent storage of carbon dioxide and siting, construction, operation, testing, monitoring, and closure.

EPA has delegated regulatory authority to many states to administer the UIC program for all or certain class wells. To date, EPA has authorized two states' primacy applications for the Class VI program: North Dakota in 2018 and Wyoming in 2020. According to EPA's website, the agency has authorized two applications for Class VI UIC wells and has 14 currently pending. Carbon dioxide leakage from a CCUS project could result in violations of its applicable UIC permit.

CEQ's recent CCUS guidance notes that the IIJA provides significant new funding for EPA's Class VI UIC Program. CEQ states, "To facilitate effective permanent sequestration, … the IIJA provides additional funding for implementation of [EPA's Class VI UIC] Program, including funds that could enable increased staff capacity and training at agencies with geological sequestration permitting authorities, and providing grants for States with UIC Class VI primary enforcement authority (primacy) or to States seeking primacy." To date, Class IV well applications can take up to six years for EPA to process. With this additional funding, we could start to see additional states seeking primacy, more efficient and timely agency action (such as more timely Class VI application processing), and more deployment of CCUS technologies throughout the United States.

This Legal Update provides a glimpse of the federal environmental laws that could impact CCUS projects. As CCUS continues to play a critical role in achieving climate goals, the regulatory landscape that impacts these projects will likely continue to evolve.

On the buses

Recent acquisitions of bus fleets by financial sponsors in the US, coupled with the promise of federal funding dedicated to electrification under the Infrastructure bill, and more to come in the stalled Build Back Better bill, are expected to catalyse mass scale bus electrification. But the costly and complex risks of electrifying large fleets are not to be underestimated. By Maisie Clarke.

In the second quarter of 2021 EQT Infrastructure agreed the $4.6 billion acquisition of First Student and First Transit, closing on the transaction the following quarter. First Student is the largest student transportation operator in North America, with a fleet of 40,000 buses, while First Transit carries about 350 million passengers per year at 300 locations. EQT, advised by Morgan Stanley, Simpson Thacher & Bartlett, Barclays, and BMO, closed on the acquisition before the Biden administration successfully passed its infrastructure bill. Yet, the anticipation of increased support for bus electrification was a contributory factor in the deal at the time, according to Alex Darden, a partner at EQT.

In the period between signing and close on the EQT acquisition, Carlyle, in a joint venture with Schneider Electric (AlphaStruxure), launched what they called an Integrated Fleet Electrification Infrastructure Project in Maryland. The project involves the ambitious combination of solar PV canopies, onsite generation, battery energy storage, microgrid controls, and electric bus chargers, though AlphaStruxure is working on a much smaller scale than EQT, with 44 buses to be supported by the project.

A pivotal point in EV transition

Tom Rousakis, leader for US infrastructure transactions at EY, is confident that "we are at the pivotal point in the EV transition." He believes that while the infrastructure bill provides the much-needed capital to build a market around electric buses to meet the need of large-scale deployment, the challenge will be to local agencies that will need to navigate this evolving market and manage fleet transitions with caution.

Bus electrification would not be receiving so much attention were it not for the amount of federal dollars that it is attracting. The new law allocates $2.5 billion to zero-emission electric school buses and a further $2.5 billion toward zero and low-emission school buses, including both electric and alternative fuel vehicles. It allocates another $7.5 billion to transit agencies and a further $7.5 billion to EV infrastructure. How far these federal dollars will go in terms of a nation-wide bid for electrification remains to be seen, but it's certainly a start for enticing private investment.

The Unites States' 480,000 school buses account for 80% of all the country's buses, but less than 1% of that total is electrified. It is estimated that electrifying the entire fleet of US school buses would reduce greenhouse gas emissions by about 8 million tonnes per year, which explains the attention that buses received in the infrastructure bill. The new Clean School Bus program, to run between 2022 and 2026 will see the US Environmental Protection Agency cover up to 100% of the costs of replacing existing school buses, including charging or fuelling infrastructure and the vehicles themselves.

States have already been allocated over $480 million in funding for electric school buses and infrastructure, with $180 million of that total in the form of Volkswagen settlement funds. The Volkswagen (VW) settlement was agreed in 2016 in the wake of a scandal in which VW was found to have faked diesel emissions tests, and the settlement has been the primary source of funding for electric school buses in 28 states. But the settlement is a one-time funding source that many states have already drained and the rest will soon deplete. There are still state green banks that can meet critical parts of any funding requirements, but additional sources of capital are needed to ensure the growth of this new market. Private investors and public-private partnerships (P3s) look like the logical next steps, particularly for school districts. P3s might allow governments to reduce their exposure to the risks attached to bus electrification. Given the abundance of risks associated with bus electrification, P3 could be vital in allowing the market to scale up.

EV bus fleet risks and costs

The list of risks in electrifying any bus fleet, whether school or transit agency, is extensive. Substantial market capacity issues, particularly when it comes to battery range and reliability, are currently the highest impediment and source of costs for these transitions, both in the US and arguably globally. A battery-operated bus has a significantly reduced range compared to that of a diesel bus. The stop and go nature of buses is a challenge, as are weather conditions and landscape. Batteries degrade over time, which creates uncertainty for bus operators around the cost of operations. The state of the battery market, in terms of technology and manufacturing, needs to evolve further to meet the demand of wide-scale electrification.

Outside of battery concerns, the next most prevalent risk is the lack of infrastructure needed to support the transition. Existing charging depots will need to be retrofitted or new depots built. Those depots will need access to suitable power supplies, which will require partnerships with local utilities. The distribution and location of fast flow charging will need to accommodate both the lower range of battery-powered buses, and bus routes themselves may need to be adapted. Pilot technologies are being developed for in-road charging, but they would still present logistical challenges, in terms of distribution and traffic interference. Electric buses also present challenges to how agencies approach costs, because unless they can evaluate a purchase's total cost of ownership, they may struggle to demonstrate affordability. An electric bus can cost up to twice as much as a diesel bus but because they use fewer moving parts, the cost of maintenance is likely to be reduced over time.

Governments and operators will also need to get a handle on new forms of volatility in energy prices. Transit operators are used to turbulence in fuel costs and have the hedging strategies in place to manage them. However, the volatility in electricity prices can be even greater, particularly in states such as California, Arizona and Massachusetts that employ time-of-use rates for electricity. Managing where and when to charge, alongside electricity cost fluctuations, not to mention making any required electrical grid improvements, understandably deters private investment in electrification. That's where federal funding comes into play, particularly in states that already have incentives for electrification, a list that includes but is not limited to California, Florida, Texas, Washington, and New York. Federal dollars will undoubtedly offset some of the above costs and uncertainties, and should help develop this market, but electrification will still require a leap of faith for both the public and private sector.

It will be appealing to governments to try and transfer these risks to the private sector given the complexities involved. P3 has been advertised as an opportunity for private investors to tackle challenges that public entities don't have the expertise to manage. A private EV ecosystem does look like it is emerging. At a White House press conference on 3 February, President Biden announced that Australian charging column manufacturer Tritium DCFC will this year open a factory in Tennessee to build electric-vehicle charging stations. Tritium, listed on the Nasdaq stock market via a special-purpose acquisition company, expects to produce 30,000 of its fast chargers per year. But outside general EV infrastructure, the primary opportunities for private investment in bus electrification lie in school buses.

From school fleets to transit agencies

The differences between school districts and transit agencies will be hugely significant, but electrifying a school bus fleet will be less complex than electrifying other parts of the US transport sector, as vehicles use fixed routes and limited operating hours that facilitate a greater ability to manage processes like charging. This ability is so great that opportunities for revenue generation from vehicle-to-grid conversion are being considered, with bus batteries functioning as battery storage facilities, particularly in summer months.

The primary role of school districts is to educate children, so it makes sense that they would prefer to outsource to the private sector the management and mitigation of the risks associated with their buses. Many school districts in the US already use private operators to provide and operate their fleets and those operators may be best placed to make a transition to electric buses. Given the high level of uncertainty surrounding bus electrification, P3 contracts will ask both sides to manage risks and school districts could still have to take ownership of mistakes as and when they occur.

With the influx of federal capital, school bus conversion could serve as the lower hanging fruit that will help a market around battery and electric bus technology develop, and this should benefit transit agencies over time. Recent and upcoming acquisitions in the school bus sector therefore are likely to lead to P3 deals in all areas of the electrification market.

If private infrastructure investors bite and the foundations are put in place for large scale electrified bus fleets in the US, it would seem far more likely than it does now that nationwide electrification will become feasible.

Back to the future

US solar has had a tough year, so tough that President Biden was forced to use the Defense Production Act to alleviate supply chain stasis and get the project pipeline moving again. But while the immediate crisis has dissipated, the sector still faces long-term challenges unless legislation tabled starts getting enacted. By Sean Keating

The US Department of Commerce (DoC) Auxin tariff investigation – a forensic look at whether imported solar panels manufactured in Cambodia, Malaysia, Thailand and Vietnam, which account for around 80% of all solar panels installed in the US, have been using components manufactured in China that should be subject to US tariffs – caused chaos in the US solar project pipeline earlier this year.

A report in late April by the Solar Energy Industries Association on the impact of Auxin found 318 utility-scale solar projects were subject to cancellation or delay, equating to $52 billion of utility-scale investment at risk (50,800MWdc and 5,800MWh of attached battery storage).

The irony of Auxin was that Auxin Solar – the company that petitioned the DoC to start the investigation because of its inability to compete on cost with imports – is miniscule. With just 150MW of bifacial solar panel manufacturing capacity, Auxin Solar would not even be an afterthought in a utility-scale bid. And yet the result of its actions was a developmental crisis for the US utility-scale solar market.

Auxin resolved – for a while

The Auxin problem was resolved, at least for the next two years, in June when the Biden administration, using the Defense Production Act, gave a 24-month tariff exemption for solar panels from Cambodia, Malaysia, Thailand and Vietnam.

But the stasis caused by Auxin – effectively a freeze on the project pipeline caused by fear of retroactive tariffs – demonstrated a serious flaw with the US solar supply chain in the US: the existing manufacturing base is too small to produce at a competitive price or meet domestic demand.

US solar domestic production costs are estimated to be around 30-40% higher than imports, and although the US has used a protectionist tariff system on solar imports for some time, according to Wood Mackenzie the US currently has just 7.5GWs of PV module production out of a global capacity of nearly 400GW. Protectionism was simply not delivering the required domestic manufacturing growth.

To reduce costs and become competitively priced, the US domestic supply chain needs to scale up big time, and to do that it needs the tax credits promised by the Solar Energy Manufacturing for America Act (SEMA) as part of the Build Back Better programme.

The SEMA bill, tabled last year, includes tax credits of $3/kg for polysilicon, $12/sqm of solar wafers, $0.04/Wdc for solar cells and $0.07/Wdc for non-integrated modules and $0.11/Wdc for integrated modules. Consensus among the major solar manufacturers is that those incentives are solid enough to warrant serious consideration of investment in a major expansion into US-based solar manufacturing, and with that expansion would come economies of scale and manufacturing efficiency.

Not just a manufacturing problem

But there is a problem, and it is not just a manufacturing/supply chain issue. The whole US renewables market is waiting on the various tax credits – investment tax credit (ITC), production tax credit (PTC) – that were part of the Build Back Better Act (BBBA) which, although having been passed in the House in December 2021, is still hung up in the Senate (in large part by Senator Joe Manchin). The legislation, since recast by the White House as Building a Better America, is expected to put the US renewables industry on a stable, predictable and long-term clean energy tax platform to fuel expansion, and attract new tax equity providers into the market.

For the utility-scale solar market the BBBA renewable energy proposals, if enacted (which they may well be as part of a smaller reconciliation bill given renewables tax credits are deemed the least onerous aspect of BBBA by its detractors) could mean the following:

- Reinstatement of the 30% commercial ITC and extended eligibility until 31 December 2031.
- Introduction of 10% bonus credits for meeting certain domestic manufacturing requirements and constructing in low-income locations.
- Reintroduction of the PTC for solar facilities, offering an alternative to the ITC.
- Introduction of a 30% ITC for standalone storage facilities.
- Introduction of incentives targeting the domestic manufacturing of panels, inverters, and trackers.

The introduction of a direct-pay provision for the various tax credits could, dependent on the final terms of the provisions, pull in new tax equity providers – for example, tax-exempt entities like pensions and endowments that have historically been unable to invest in renewables generation could do so because a direct-pay provision would essentially make the credits refundable and treat the amount of the tax credit earned as tax paid by the project owner.

Tax equity

And new tax equity is sorely needed because demand is growing way beyond supply, which has remained stubbornly static at around $20 billion for the past two years across the US wind and solar sectors. And as US offshore wind picks up, which will eat into large chunks of existing tax equity appetite, the gap between supply and demand looks set to grow.

Under existing legislation large additions of utility-scale solar capacity is likely to continue because of the extension of the solar ITC: for projects that have started construction in 2021 and 2022 the ITC is 26%, 22% in 2023, and 10% in 2024 and thereafter. For any project to receive more than a 10% ITC it must also be in service before 2026, which is why the stasis caused by Auxin was so potentially damaging had it gone on for a long time.

Similarly, although the production tax credit (PTC) expired at the end of 2021, dependent on start of construction date from 2016-21, a project can still qualify for 40% to 100% PTC value if it meets commercial year-end operation deadlines from 2022 to 2025.

Moves to grow US solar supply chain

Auxin, and to a far lesser extent the slow movement on BBBA renewable energy credits, caused considerable damage to a market that was expected to boom this year. Rystad estimated the US would add another 27GW of solar energy in 2022. Given the confluence of the Auxin probe, the high cost and short supply of domestically manufactured solar components, and the inability to get new legislation beyond first gear, Rystad has since revised its estimate to around 10GW for the year.

Estimates are that the US needs to install around 50GW of solar PV capacity each year from 2022 to 2030 to keep the country's emissions reduction plans on track –10GW this year does not bode well. But efforts to resolve the domestic solar supply chain issue are beginning to gather momentum both from within and, perhaps more significantly, outside the political establishment.

AES, Clearway, Cypress Creek Renewables and D. E. Shaw Renewable Investments (DESRI) have launched the US Solar Buyer Consortium, which issued an RFP for qualified manufacturers that can commit to a long-term strategic partnership to supply up to 7GW of solar modules per year starting from 2024. The move is expected give manufacturers the certainty of $6 billion of future orders to underpin expansion of the manufacturing base.

First Solar has also announced an agreement with National Grid Renewables for 2GW of Cadmium Telluride film solar modules to be delivered in 2024 and 2025 throughout the United States. First Solar broke ground on its third manufacturing facility in Ohio last year. The 3.3GW facility is scheduled to start operations in the first half of 2023, upping the company's north-western Ohio footprint to a total annual capacity of 6GW, which would make it the largest fully vertically integrated solar manufacturing complex outside of China.

Provence Grand Large: A matter of scale

A first for France and the first floating wind pilot-project globally to have been financed with limited recourse commercial bank debt, Provence Grand Large is a significant step in the development of a bankable floating offshore wind sector. But the project is only 25MWs and scaling up still poses significant angst for some bank credit committees. By Thomas Hopkins.

The Provence Grand Large (PGL) project financing is a pioneering transaction for the floating offshore wind industry. An inventive mixture of subsidies and non-recourse debt, the financing could help to address lingering concerns about technology risk and demonstrate the bankability of utility-scale floating offshore wind farms to lenders.

The potential benefits of floating offshore wind have been touted for a number of years, but the sector has yet to emerge as an established project finance asset class. As the very first project financing of a floating offshore wind farm, the financing of the 25MW PGL project may alter this trend. PGL will be located off the coast of Port-Saint-Louis-du-Rhone, France and is sponsored by EDF Renewables and Enbridge Eolien France 2, a subsidiary of Enbridge and CPP Investments.

The project reached financial close in November 2021, but the deal was only announced in the middle of 2022 due to litigation concerning PGL. An environmental association challenged the content of the project's environmental permit in court. The Court of Appeal then partially upheld some of the arguments made by the association, but only to compel the French government to re-issue the environmental permit with different prescriptions and the project now has a valid environmental permit with the changes requested by the court. The environmental group could challenge the permit again, although it is currently unknown if further litigation will be launched.

The first of four pilot projects

The PGL project is one of four pilot projects awarded in a 2016 tender designed to test the viability of floating offshore wind. The other three projects include the Groix & Belle-Ile, Eoliennes flottantes du Golfe du Lion (EFGL), and Eolmed wind farms, all of which have a capacity of around 30MW. Commenting on the rationale behind the tender, Guillaume Leprieur, head of the structured finance office for EMEA in France at MUFG, says: "Floating offshore wind has been at the top of the agenda for the French government, because there is a realisation that a lot of the offshore wind resource in France is in water deeper than 60 metres and only accessible by floating offshore wind technology. This is particularly true in the Mediterranean. There is also a realisation that if wind turbines are located further away, the visual impact is less important."

According to a source close to the transaction, the project has secured €286.5 million of debt, as well as €108 million of subsidies. Lenders on the transaction include BNP Paribas, Credit Agricole, Natixis, Societe Generale, Caisse d'Epargne, MUFG, Rabobank, Santander, and the EIB. The subsidies are provided by the European Commission (a €25 million NER 300 subsidy), the European Regional Development Fund (ERDF) (€5 million), and Agence de l'Environnement et de la Maitrise de l'Energie (ADEME) (€78 million).

The project financing is structured as a club deal and comprises a €130.7 million term loan from the commercial banks, a €47.7 million term loan from the EIB, a €6.8 million standby facility (commercial banks), a €2.3 million standby facility (EIB), a €5 million working capital facility (WCF), a €4 million revolving VAT facility, a €13.5 million L/C facility, a €9 million debt service reserve facility (DSRF), and a €67.6 million equity bridge loan.

The term loans, standby facilities, DSRF, L/C facility, and WCF have a door-to-door maturity of twenty years and two months, while the revolving VAT facility has a tenor of up to five years and the equity bridge loan has a tenor of up to two years and eight months. Societe Generale is financial adviser and DNV is the lenders' technical adviser. Clifford Chance is legal adviser to the sponsors, while Linklaters is counsel to the lenders.

Mitigating intercreditor issues and technology risk

The subsidies that the project received created some intercreditor issues in terms of the seniority of the subsidies in relation to the senior debt. The subsidy providers can be entitled to recoup the subsidies in certain circumstances, such as if the sponsors do not complete the project or if the project is successful beyond the expectations of the sponsors. Consequently, an intercreditor agreement between the senior lenders and the subsidy providers was necessary to codify the rights and obligations of the respective parties.

The financial aid granted to the project by Ademe consists of both pure subsidies and repayable advances. The advances are divided into two portions known as ARV1 and ARV2. Only the ARV1 portion ranks pari passu with the senior debt, while the ARV2 and pure subsidy portions are subordinate to the senior debt. The risk to lenders of subsidy providers reclaiming funds granted to the project is also reduced through guarantees to the project company from the sponsors in respect of the subsidies from Ademe, the EU Commission, and the ERDF.

PGL has a 20-year feed-in tariff priced at €240/MWh, with an indexation coefficient applied annually. It is the first project to use the tension leg platform, which is attached to the seabed and houses the turbine while floating on the surface of the water. The platform has been designed by SBM Offshore and IFP Energies Nouvelles and has environmental benefits, as it causes minimal disruption to the seabed. Dynamic cabling that can adapt to currents and swells will be used to transfer electricity from the wind farm to the shore. Prysmian is supplying the cables, while Siemens Gamesa is supplying the turbines. The project is expected to be commissioned in 2023.

Discussing the use of new technology on PGL, Nathalie Lemarcis, a managing director and co-head of energy advisory and project finance in London at Societe Generale, says: "The due diligence does focus on the technological differences between bottom-fixed and floating and in that respect, there is a focus on the floater technology and its interaction with the turbine. There is also an element of scale up risk, including in the use of high voltage dynamic cables for the electrical system. I think that lenders appreciate that floating offshore wind does not have a long track record, but are trying to get comfortable with the approach that has been followed by the developer to put together the project through the certification process. I think that the heavy maintenance of the wind farm is also an area lenders had to consider especially in the early years of the project."

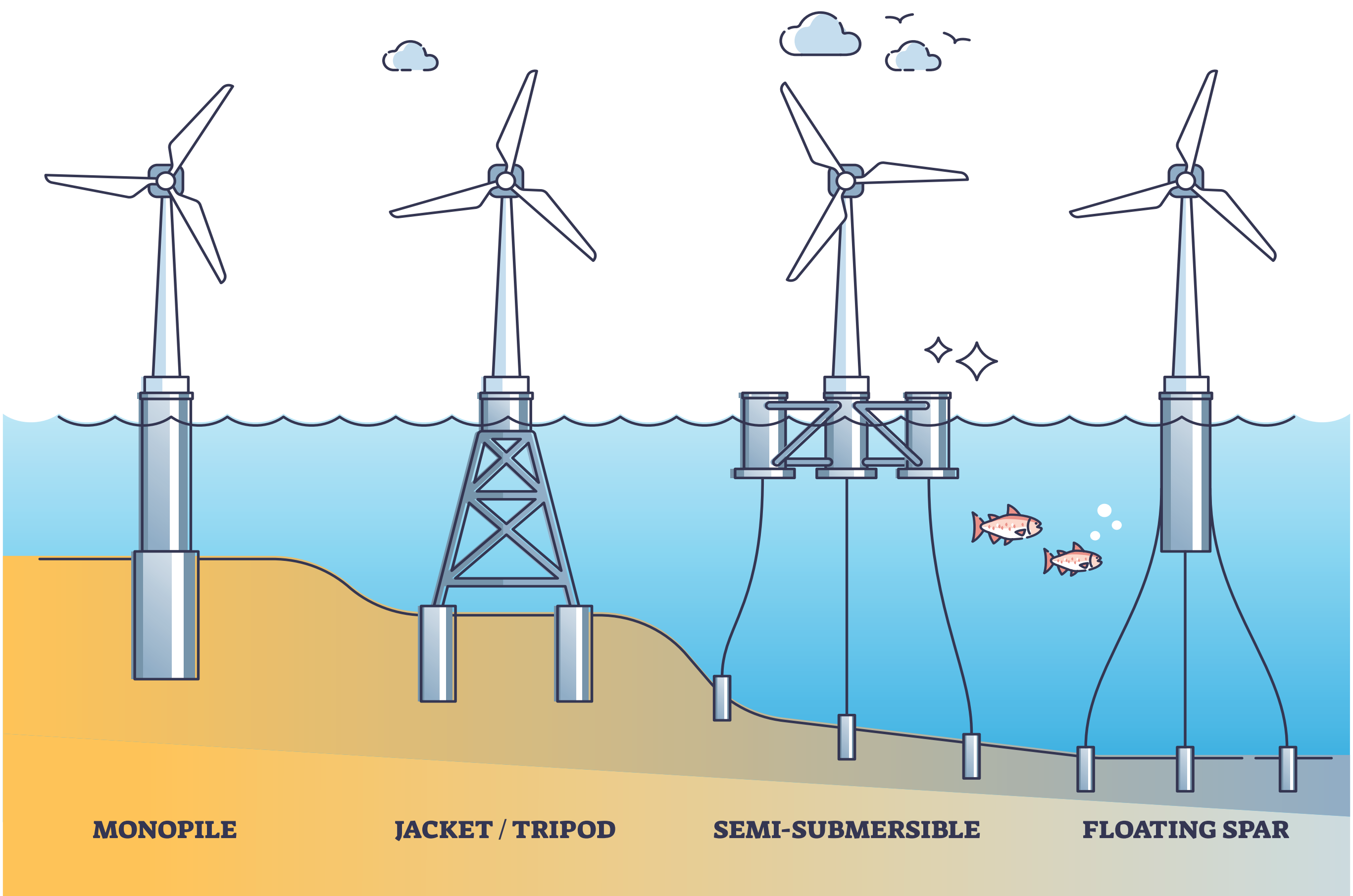
Technology risk was, therefore, a crucial factor evaluated by lenders when closing the financing, with some components used for the first time. As Lemarcis points out, it was important for lenders to understand the interface between the turbines and the floating platforms, as there is obviously a possibility of project failure if the two technologies do not work together effectively. Lenders also had to become comfortable with the risk of scaling up parts of the wind farm in real-world conditions. In addition, lenders had to assess the impact of maintenance work on project revenues, including individual turbines being towed to port for repairs.

A significant deal

There can be no doubting the notability of the PGL financing, which has seen a significant amount of long-dated non-recourse debt raised for a project that is the first of its kind. Sponsors and lenders have managed technology risk effectively, delivering a deal that has afforded floating offshore wind an entry point into the project finance market. Floating offshore wind technology also has immense value, as it allows wind turbines to be installed further offshore and in deeper water, maximising the use of wind resources and reducing viewshed impacts, as well as making it easier to avoid shipping lanes and fishing zones. The backing of project finance lenders will help to accelerate the growth of this new frontier for renewable energy.

It seems that PGL has already opened the door for other floating offshore wind transactions. Both the EFGL and Eolmed projects have reached financial close in the months following the PGL deal. The projects received subsidies from Ademe

TYPES OF OFFSHORE WIND TURBINES



and PGL has shown that such subsidies can be successfully integrated with senior debt within a project financing. The French government also plans to launch the A05 and A06 tenders for floating offshore wind. The A05 tender will aim to procure a wind farm with a capacity of 230-270MW and the A06 tender will look to procure two wind farms, each with a capacity of around 250MW. Timelines are not entirely certain, but work on the tenders is in progress. A05 and A06 could, in short, see larger floating offshore wind farms developed in France.

It is clear, however, from the PGL transaction that the path from financing a 30MW project to financing a 250MW project will not be entirely without complications. Aspects of the PGL deal are relatively conservative, as is evidenced by the employment of an L/C, a DSRF, and a standby facility. Liquidity for the transaction was also boosted by DFI debt and subsidies. It is only natural that lenders were cautious about financing new technology, but it is not yet apparent if there is sufficient liquidity available to finance large-scale projects. At this stage, only a small number of banks have had approval from their credit departments for financing floating offshore projects on a non-recourse basis.

Eliminating technology risk and establishing a stable operational history for floating offshore wind assets are critical if a solid pipeline of projects is to emerge. As Francois April, a partner at Linklaters, notes: "Once the technological risks have been tested to the satisfaction of the sponsors and the senior lenders, I think we can move on to larger-scale floating offshore wind projects with more confidence. I think we need to see how the commissioning and the operation of the pilot projects goes. Even if we keep smaller projects, until technological risks have been tested and considered to be acceptable, we will still need subsidies before we can move on to larger projects."

Although PGL has been subject to litigation, floating wind farms could be less likely to provoke legal action than conventional wind farms, as floating projects can be placed further away from the coast. This will aid French offshore wind development, which has long been plagued by fervent anti-wind sentiment from local residents. Almost by design, PGL and the other three floating offshore wind projects will also offer global project finance lenders a vital litmus test of the reliability of this innovative new technology.

Plaquemines: Stepping on the LNG

Speed and its modular LNG model are the hallmarks of Plaquemines LNG sponsor Venture Global. But at least some of its potential European offtaker customer base still seems a little reticent to making long-term commitments despite their energy security concerns and the status of LNG as a transition fuel

With two major US LNG project financings under its belt – the $7.3 billion Calcasieu Pass LNG 10 mtpa project in 2019 and the $13.2 billion Plaquemines LNG 13.33 mtpa phase one and associated Gator Express Pipeline project, signed last month – it is easy to forget that privately-owned Venture Global was founded just nine years ago in 2013 by Bob Pender and Michael Sabel.

The founders were well-connected: Pender previously served as a partner at Hogan Lovells and was co-leader of the firm's global energy and natural resources team; and Sabel was previously executive vice-president of First Sierra Financial and had held a number of other investment banking roles. But it was the development model they came up with – modular LNG construction that could be built quicker than past LNG projects, a model that persuaded lenders to accept no sponsor completion guarantees without upping the cost of debt significantly – complemented by a long list of very creditworthy offtakers that made the Calcasieu Pass template such a success in 2019.

With the recently closed Plaquemines LNG financing, Venture Global has repeated that template. Calcasieu Pass started producing LNG in January 2022, and the build timeline is similarly ambitious for Plaquemines LNG – construction began in August 2021 prior to financial close, and the 13.33 mtpa phase one of the 20 mtpa project is planned to come online in 2024. Venture Global awarded a contract to Baker Hughes in March for a liquefaction train system, which is expected to begin deliveries in the first half of 2023. A joint venture of KBR and Zachry Group will oversee engineering, procurement and construction (EPC) of the project, and McDermott's CB&I unit will provide the two 200,000 cubic metre storage tanks.

The deal, again like Calcasieu Pass, is also underpinned by strong offtakers. Venture Global has executed 20-year sales and purchase agreements (SPAs) for 80% of the full 20 mtpa project. Plaquemines LNG phase one customers include PGNiG, Sinopec, CNOOC, Shell and EDF; phase two customers announced to date include ExxonMobil, Petronas and New Fortress Energy.

Holdco/opco structure

The debt financing for the scheme includes holdco and opco facilities. The holdco debt totals $2.1 billion and is structured as a two-year L/C for borrower

Plaquemines LNG Funding LLC. The lenders are Bank of America, Goldman Sachs Bank USA, MUFG, Mizuho, Banco Santander, CaixaBank, Deutsche Bank, ICBC Standard Bank, ING Capital, JP Morgan Chase Bank, LBBW, Natixis, Royal Bank of Canada, SMBC, Bank of Nova Scotia and Nomura.

The opco financing totals $9.95 billion and is split between an $8.45 billion seven-year term loan and a $1.1 billion seven-year working capital facility. The lenders are Bank of America, Goldman Sachs Bank USA, MUFG, Mizuho, Morgan Stanley, Banco Santander, Bank of China, CaixaBank, Deutsche Bank, ICBC, ING Capital, JP Morgan Chase Bank, LBBW, Natixis, Royal Bank of Canada, SMBC, Bank of Nova Scotia, Nomura and Truist Bank. Latham & Watkins provided sponsor counsel and Skadden, Arps, Slate, Meagher & Flom acted for the lenders.

Keeping the pedal to the metal on all project fronts appears to be the Venture Global hallmark – the developer raised $675 million in equity for Plaquemines LNG even prior to it closing on the Calcasieu Pass LNG financing in 2019. And, as Sabel notes, given global (primarily European) energy security concerns in the wake of Russia's invasion of Ukraine and LNG's status as a viable transition fuel, "speed matters more than ever". And the pace at the sponsor looks set to continue. Venture Global is already marketing offtake for its third project, CP2, and has signed SPAs with ExxonMobil and New Fortress Energy for the scheme.

Striking a balance

The 20-year offtake agreements for Plaquemines LNG have significance for US LNG market growth prospects. European buyers have traditionally generally been unwilling to go long on offtake for US LNG, leaving Asian buyers and aggregators with fairly free rein. Calcasieu Pass was a notable exception to that trend when Shell, Galp, Edison S.p.A, BP, Repsol and PGNiG signed up to 20-year offtakes, albeit Sinopec also signed a 3.5 mtpa 20-year offtake with the project in 2021.

Given Europe is now looking to wean itself off of Russian gas permanently, and Venture Global's past success with European offtakers, the offtake line-up for Plaquemines is arguably a little European-light. Like Calcasieu, Plaquemines also has PGNiG and Shell, along with EDF, as long-term European offtakers for phase one, but also China's CNOOC and Sinopec. Of course this makes little difference to the project's fundamentals, lenders or the borrower, but it does illustrate that even with energy security concerns spawned by the war in Ukraine, some European buyers may still be wary of long-term commitments given the extreme pricing volatility in the LNG market over the past two years.