ReedSmith

Driving progress
through partnership

Energy **transition**

an evolving journey

Foreword

By Praj Samant

Late last year, world leaders gathered at COP26 to set targets for decarbonizing the global economy. The table was set for the energy transition, and the energy industry was moving quickly to understand how it could continue to evolve to help governments achieve these ambitious new targets...

Since then, the energy landscape has changed dramatically. Russia's invasion of Ukraine forced nations and trading blocs to focus their immediate attention on energy security. With this shift in priorities, progress toward a carbon-neutral economy has slowed but certainly not stopped.

In fact, some in the industry see the energy transition as a direct route to energy security. If a country can produce enough energy from its own renewable sources, then it would not need to rely on imports from anyone.

This of course is a long-term view, and immediate energy requirements need to be dealt with. Improving energy security has become a more complicated picture since the United States, United Kingdom and European Union imposed sanction regimes on Russia and its energy industry. Trading blocs and countries, once reliant on Russian oil and gas, have been forced to look further afield for new suppliers and trading partners.

Even as the energy landscape continues to evolve, it is not commercially viable to significantly reduce production of fossil fuels while they remain in such high demand. Such a move would not help governments improve their energy security, nor would it lower the spiraling cost of energy for consumers.

What remains clear is that the energy industry needs incentives to accelerate the energy transition. This requires a tax policy that supports industry making the changes required to decarbonize the global economy. It also requires significant investment in the infrastructure required to support the generation of enough renewable energy for global consumption.

Regardless of the current energy landscape, the ambition of achieving a carbon-neutral global economy remains. This huge change presents new risks and opportunities.

This June 2022 report looks at those risks and opportunities. It examines what a decarbonized world might resemble and the role the energy sector will play within it. Topics considered include: the role of LNG; which clean fuels will really take off; the role of renewables; carbon capture and battery storage; a potential nuclear renaissance; a patchwork of regulations regulating hydrogen as a fuel; and how the new world of energy will be financed.

We invite you to reach out to any of our authors to discuss the issues we address and what they mean for your organization.

Praj Samant

Praj is chair of the firm's Energy & Natural Resources Industry Group, and is based in Reed Smith's London office. He has over 20 years of experience representing a wide range of banks, exchanges, hedge funds and energy and commodity companies in a variety of transactional, cross-border regulatory, compliance and risk management matters within the energy sector.

Energy **transition**
an evolving journey

CHAPTER

01

Decarbonization…and beyond

Taxing carbon at the border: Current state of play

By Adam Hedley, Todd Maiden, Yves Melin, Wim Vandenberghe, Philippe Heeren, Jin Woo Kim and Eric Schmoll

Takeaways

- Under the EU's CBAM, importers will be required to pay for carbon-intensive imports into the EU
- The EU is expected to introduce its CBAM in 2023, and other countries are currently discussing the introduction of their own measures
- The EU's measures will likely set the pace, with possibly conflicting rules adopted elsewhere
- Calculating carbon contents of imports and payments will require significant preparation work from exporting and importing companies
- Covered goods do not include energy goods yet

The European Union (EU) and a growing number of countries around the world are working on taxing at their borders the greenhouse gas (GHG) emissions embedded into imported products. This is seen, especially in Europe, as the only way to adopt an ambitious agenda for reducing GHG emissions and creating a level playing field where domestic and third-country producers pay the same level of emission rights or tax for the same product.

With its Carbon Border Adjustment Mechanism (CBAM) proposal, the EU takes the lead in setting up such a field, but other environmentally impactful countries, including the United States, are discussing their own measures. In this article, we take stock of the CBAM, and similar initiatives in the United States, Canada, the United Kingdom, South Korea, and China, and we explore what they mean for global businesses and the energy sector.

* * *

The EU is expected to introduce the CBAM in 2023, which means that payment of CBAM certificates upon importation would already be required in 2026. Calculating how much is to be paid at the EU border will require knowledge of how much carbon is embedded in the imported product. Alternatively, the importing company can demonstrate that it has already paid emission rights elsewhere. The EU will indeed recognize certain foreign emissions reduction schemes as equivalent to the EU's own Emissions Trading System (ETS). Such "equivalence recognition" is mainly determined through bilateral discussions between the EU and the third country concerned. This bilateral engagement with the EU is likely to create an incentive for third countries to develop their own emissions reduction measures, which may lead to multilateral harmonization among like-minded countries. However, we are likely to see in the interim period a patchwork of different carbon pricing systems in different jurisdictions before countries agree to create a global or plurilateral carbon pricing system. The CBAM and similar schemes are also likely to apply to a rapidly growing list of products that will extend beyond the current products and commodities in scope. This is an area to watch, urgently.

European Union

The European Commission tabled a proposal implementing the CBAM on July 14, 2021. This proposal is now with the EU's two co-legislators: the European Parliament and the European Council. The Council already approved the Commission's draft proposal, with minor changes, in March 2022. The Parliament is expected to adopt its own version, in June 2022. The text will then be finalized by the Parliament and the Council, in the presence of the Commission (a process known as a "trilogue"). The legislative process is expected to be completed by the end of the year.

The proposed CBAM aims to guarantee that carbon emissions embedded in imported goods are equally taxed in comparison with domestic productions, the latter being currently subject to the EU Emissions Trading System (ETS). This means that EU importers must pay for the carbon embedded into CBAM-targeted goods that are placed on the EU market by purchasing CBAM certificates upon importation.

The CBAM is expected to enter into force as early as 2023 in a transitional form, and it is likely to fully apply from 2026. During the transitional period (2023-2025), EU importers will have to comply with reporting requirements, but will not need to purchase CBAM certificates yet. Once the CBAM is fully in place from 2026 onward, importers will be required to purchase CBAM certificates in order to import CBAM goods into the EU.

The key features of the CBAM, once it is fully in place from 2026, are as follows:

- Targeted sectors: Five emissions-intensive, trade-exposed industries under EU ETS are targeted in the current proposal. In the first phase, the CBAM will impose a carbon price on imports of cement, fertilizers, iron and steel, aluminum, and electricity. However, the EU's ultimate objective is a broad product coverage of the CBAM, possibly including energy and other products.
- Authorized declarants: CBAM goods must be cleared through customs by declarants who are authorized to do so.
- CBAM declaration: EU importers must submit a CBAM declaration for the preceding year on the number of imported goods and their total (verified) embedded emissions. Embedded emissions in imported goods will be calculated on the basis of direct emissions of GHG per ton of goods produced in the production installations.
- CBAM certificates: EU importers must purchase CBAM certificates corresponding to the embedded emissions in the imported goods. The embedded emissions are either based on the default value or on the actual proven emissions, if lower.
- Carbon prices already paid in the country of origin: CBAM certificates can be reduced to account for carbon prices already paid in the country of origin, but this needs to be certified by an independent person.
- Geographical exemptions: Countries that adopt the EU ETS (Iceland, Norway, and Liechtenstein) or are linked with the EU ETS (Switzerland) are exempted from the CBAM. The EU will further elaborate a mechanism for other third countries to be exempted in the future.

While the CBAM may not initially cover energy products, it is expected to expand its targeted sectors quickly. For instance, before 2026, the Commission will consider broadening the CBAM to sectors identified as having the highest risk of carbon leakage in Decision (EU) 2019/708, which includes hard coal, crude petroleum, iron ores, non-ferrous metal ores, and others. It is therefore important for companies to pay close attention to the further development of the CBAM, even after its implementation.

United States

The United States is considering the implementation of its own mechanism to tax carbon emissions at the border, although it trails the EU in the development of such a program due to a lack of consensus in Congress.

In July 2021, similar versions of legislation creating the Fair, Affordable, Innovative and Resilient Transition and Competition Act (FTCA) were introduced in the House of Representatives and the Senate. The legislation seeks to impose a cost on the GHG emissions associated with imported goods "to account for the marginal increased costs incurred by U.S. businesses to comply with laws and regulations limiting greenhouse gas emissions." The bills require the Treasury Department to determine (1) the costs that U.S. companies in the covered sectors incur to comply with U.S. environmental policies, and (2) the quantity of greenhouse gas emissions associated with the production of each covered good.

As drafted, the FTCA would, among other things:

- Impose a "border carbon adjustment" fee on imports of carbon-intensive goods into the United States, including but not limited to steel, aluminum, cement, and fossil fuels.
- Apply to regulated products made with "covered fuel," defined as natural gas, petroleum, coal, or any other product derived from natural gas, petroleum, or coal that is used or may be used so as to emit GHGs into the atmosphere.

Unlike its EU counterpart, the FTCA is not accompanied by an equivalent domestic tax or price on carbon emissions per se – but it would impose a residual cost to offset the carbon emission costs incurred by compliant U.S. businesses.

The FTCA faces some hurdles. First, it has not advanced far (in terms of the congressional committee review process) after almost nine months. For example, the House version of the FTCA was introduced by a Democrat and was only co-sponsored by one other Democrat. Since being introduced, it has been referred to several different committees but has failed to pass out of any committee, let alone come up for a vote on the floor of the House, after which it would need to be approved in the Senate, where bipartisan approval will likely be needed and will be harder to achieve. Second, it is likely that ongoing conflict in Ukraine will further raise energy prices, which makes it less likely that the FTCA will pass in the near term. Finally, any U.S. carbon border adjustment will be scrutinized closely by U.S. trading partners, both in terms of its impact on trade flows and its consistency with World Trade Organization rules.

However, there are some existing CBAM-like programs in the United States that could create a precedent for future federal regulation in this area. California already has its own Low Carbon Fuel Standard (LCFS). The LCFS incentivizes regulated companies to utilize transportation fuels with relatively low carbon intensity (CI) in gas, diesel, and alternative fuel substitutes. CI is measured and benchmarked, with regulated parties needing to prove compliance with the fuels they sell in California.

The CI of each regulated fuel/substitute has to be measured through an approved "pathway" that will calculate carbon emissions associated with the fuel and its transport into California from anywhere in the world. Relatively low CI fuels generate "credits." High CI fuels that are above the benchmark are issued "deficits." Regulated parties above the benchmark can offset their compliance deficits and meet the benchmark by purchasing credits from compliant parties. In this way, the LCFS program incentivizes parties to transition to low CI fuels and substitutes to avoid these extra offset purchase costs.

Other states, including Washington and Oregon, have developed, or are developing their own LCFS or "Clean Fuels" programs. These states have coordinated with British Columbia to collectively form the Pacific Coast Collaborative for, among other carbon-reduction initiatives, forming a west coast LCFS trading market. New York and New Mexico are considering LCFS programs, as are other states.

Canada

Canada has shown interest in using a CBAM-like measure to tax carbon emissions at the border so as to reach its United Nations Framework Convention on Climate Change (UNFCCC) goals (for example, the stated 2021 goal of a 40-45 percent reduction below 2005 levels by 2030). Canada's version of the measure is called Carbon Border Adjustments (CBAs).

In August 2021, Canada issued a lengthy "Consultation" on "Exploring Carbon Adjustments for Canada." Among other topics, the Consultation considered the potential of CBAs both for import charges and export rebates. Examples include:

- Import charges applied to goods from countries that either do not have carbon pricing or apply a lower carbon price to ensure that they face similar carbon costs (such as per unit of emission resulting from the production of a good) to those that apply to domestic producers.
- Other measures that could apply a carbon price to imported goods include a domestic tax or charge levied on both high-carbon domestic and imported products or a requirement that emissions allowances be purchased for imported goods based on their carbon intensity.
- Export rebates provided to producers so that domestically produced goods compete on equal footing in foreign markets, alongside goods from countries with limited or no carbon pricing.

The Consultation pointed out the many complexities of using CBAs, including the impact on international trade. All of these hurdles were identified prior to recent developments in Ukraine, which will only complicate supply and demand issues further. The Consultation came to a non-committal conclusion that "[…] the Government intends to continue its discussions with Canadians and international partners over the coming months on this issue."

Since the Consultation was published, there appears to have been relatively little advancement on CBAs. First, the 2022-2023 Departmental Plan from Environment and Climate Change Canada does not list CBAs as part of its named tools for achieving climate change goals during this period. Second, a March 22, 2022 search for pending legislation currently introduced in either the Canadian Senate or House of Commons returned no results when searching for "carbon border adjustments."

United Kingdom

Currently, the United Kingdom partially addresses the risk of carbon leakage through the UK Emissions Trading Scheme, which grants free allowances for emissions to manufacturers at risk of carbon leakage.

In September 2021, an inquiry into the merits of introducing a mechanism to tax carbon emissions at the border was launched by the Environmental Audit Committee (EAC) of the UK Parliament. It aimed at collecting evidence to assess the role of such a mechanism in targeting carbon leakage risks and its potential role in broader long-term environment objectives, like decarbonization.

At the moment, the potential adoption of a UK CBAM is under assessment and no specific timelines have been published yet. Meetings on the UK CBAM at the EAC are still ongoing. A UK CBAM, in line with the EU initiative, would further address the risk of carbon leakage in the sectors that are caught by the UK ETS.

South Korea and China

South Korea and China also address the risk of carbon leakage through their own emissions trading system:

- South Korea launched its emissions trading system (K-ETS) in January 2015, which was East Asia's first nationwide mandatory ETS and, at the time, the second-largest carbon market after the EU ETS. The K-ETS covers 685 of the country's largest emitters, accounting for 73.5 percent of national GHG emissions. It covers direct emissions of six GHGs, as well as indirect emissions from electricity consumption. The K-ETS plays an essential role in meeting South Korea's 2030 updated NDC target of a 24.4 percent reduction from 2017 emissions. In 2021, the K-ETS entered its third phase.

- After China launched its national ETS politically in December 2017 and built on its experience of piloting carbon markets in eight regions, it launched the national ETS in 2021. Key pillars of the development of the national ETS include reporting and verification of historical emissions data from eight emission-intensive sectors; development of the national registry, trading system, and national enterprise GHG reporting system; set-up of the legislative and regulatory framework; and capacity building. The existing Chinese regional ETS pilots are gradually transitioning into the national ETS.

At the moment, South Korea and China are not discussing a CBAM-like initiative in concrete terms. Rather, their focus is on how to address and limit the potential impacts of the introduction of the EU CBAM. In this context, some have flagged the introduction of a Chinese and South Korean CBAM-like mechanism, but this has not been followed up with concrete legislative proposals yet.

Authors

Adam Hedley

Adam is a partner in the London office and has 12+ years of experience advising on a broad spectrum of UK, EU and international environmental, health & safety, product compliance, carbon market and climate change law matters. He has a particular focus on the environmental aspects of ESG, and regularly advises on key topics, such as: climate change adaptation and mitigation projects; climate-related corporate reporting; carbon offsetting and neutrality objectives; renewables and alternative/sustainable fuels regulation, compliance and incentive schemes. He also regularly works on EU and international carbon and climate-related transactions, advisory matters and disputes, including emissions regulation, carbon trading and climate financing projects. His experience spans cap-and-trade schemes such as the EU, UK and Swiss ETS and regulatory / voluntary carbon offsetting schemes, including the UNFCCC CDM, the emerging Paris Agreement Article 6 mechanisms, CORSIA, REDD+, Gold Standard, VCS, etc. Adam is also experienced in EU renewable energy/fuel laws, and claiming/trading of UERs, RTFCs and other forms of green certificate. He has regularly been ranked as a "rising star" by *Legal 500* and as "up and coming" by *Chambers UK*.

Todd Maiden

Todd is a partner in the San Francisco office with more than 30 years of experience helping clients maximize business opportunities and manage risks associated with environmental, energy, climate change and ESG/ sustainability issues. He particularly prides himself on understanding his client's motivations and risk tolerances to provide cost-effective and practical guidance. His practice ranges from regulatory and business counseling to negotiating corporate and real estate transactions, as well as resolving administrative enforcement actions and litigation matters. Todd is also a member of the firm's global environmental, social and governance (ESG) advisory committee. He has a particular focus on the environmental and governance aspects of ESG.

Yves Melin

Yves has 20 years of experience as an international trade and customs lawyer in Brussels. He concentrates on trade remedies (anti-dumping measures, countervailing measures and safeguards re-balancing duties), customs laws and procedures, sanctions, export and import controls, and carbon trading and border adjustment. Yves has represented clients in more than 100 trade remedy investigations, and before the EU Courts in more than 30 disputes relating to international trade and customs laws, including in the landmark cases Ikea Wholesale (C-351/04), XinYi PV (T-586/14) and Jiangsu Seraphim (T-110/17) cases. He is part of the firm's global environmental, social and governance (ESG) practice, with a particular focus on supply chain due diligence and the enforcement of environmental (carbon border adjustment, deforestation, etc.) and labour (anti-slavery, compliance with ILO conventions) standards for goods crossing the EU's and the UK's borders. Yves is a member of the Editorial Board of the Global Trade and Customs Journal (Kluwer), a research fellow in customs and trade law at the University of Liège and a lecturer in Antwerp, Liège and Porto.

Wim Vandenberghe

Wim is an EU regulatory partner in Reed Smith's Brussels office, focusing on EU product regulation, government affairs and public policy. He helps global companies to navigate the regulatory process in Europe throughout the life cycle of their products — from planning and development, to approval and marketing, to enforcement and ongoing compliance. Wim's practice includes counseling on product standards (safety, health, environment), regulatory compliance approvals (including CE marking), cross-sectoral requirements (e.g. materials and waste management, sustainability, renewables and climate change) and internal market issues. He advises on both the legal and the practical/procedural aspects of EU law-making, engaging with EU institutions to anticipate, understand, and influence policy and the legislative and regulatory developments which impact clients' businesses. Wim has law degrees from KU Leuven (Belgium), University of Edinburgh (UK) and the Centre for Energy, Petroleum and Mineral Law and Policy (UK), and teaches a course on energy regulations at King's College, London, UK since 2011.

Philippe Heeren

Philippe is an associate in the Brussels office dealing with customs and excise matters. Navigating the impact of customs and excise laws on a business' supply chain, Philippe helps clients in addressing the challenges relating to customs valuation, classification and origin, as well as formal customs laws and suspensive customs and excise procedures. In addition to providing advisory support, Philippe assists clients in solving disputes with customs authorities in Belgium and across the EU. His support spans the entire dispute lifecycle, from voluntary disclosures to customs audits, investigations and, ultimately, administrative and court proceedings. Knowing the business and achieving results go hand in hand. For his clients trading in energy products and beverages, he has developed specific experience in excise matters. Serving the public sector, Philippe has been involved in law-making efforts at the national and EU level, in particular on the rework of the EU Energy Taxation Directive.

Jin Woo Kim

Jin Woo Kim is an international trade and customs associate at Reed Smith, based in the Brussels office. Jin advises clients on EU trade remedy proceedings, World Trade Organization (WTO) dispute settlement, EU customs rules, EU-Korea trade relations, trade policy advice and new EU regulatory measures: Carbon Border Adjustment Mechanism (CBAM), Supply Chain Due Diligence, etc. Together with Yves and Wim, Jin is advising several clients on the EU CBAM and helping them to understand and prepare the new measure.

Eric Schmoll

Eric is an associate in the Energy and Natural Resources group, based in San Francisco. Eric focuses his practice in environmental, health and safety (EHS) litigation and regulatory matters. Eric assists the firm's EHS team in providing environmental, social and governance (ESG) advice to clientele, and regularly takes part in renewable energy development projects. He also counsels clients on environmental permitting and compliance, and assists on environmental due diligence in real estate acquisitions and transactions.

Scaling up carbon-neutral fossil fuels market: Voluntary standards vs. mandatory regulation

By James Atkin, Adam Hedley and Jake Williams

Takeaways

- Carbon-neutral fuel deals represent an interim solution during green energy transition
- Carbon-neutral labeling and offsetting are susceptible to being seen as “greenwashing”
- Industry initiatives to develop voluntary standards are in a nascent stage
- A global regulatory regime to regulate carbon-neutral fossil fuels is not likely soon

In the current climate of a clear and inexorable shift toward renewables and other low-carbon energy production, the notion of carbon-neutral fossil fuels sits uneasily. However, the green energy transition will take time and a huge amount of investment. In the meantime, fossil fuel producers and market actors are increasingly looking to interim green solutions; hence, the emergence of “carbon-neutral” fossil fuel deals.

“Carbon neutral” or “GHG neutral” in the context of a fossil fuel product broadly refers to the reduction and/or offsetting of carbon dioxide (and carbon dioxide equivalent greenhouse gases) emissions occurring as a result of the production, transportation, and use of the product in order to achieve a net-zero emissions outcome.

Needless to say, the use of the carbon-neutral label in this context is potentially dangerous territory. There is much debate about what the carbon-neutral label should specifically require in this context, and there is a spectrum of views on what types of emissions it should cover (some or all of scope 1, 2, and 3 emissions), how we should measure emissions, and whether reduction at source before resorting to offsetting the balance of emissions should be required.

These are all very much live issues in this nascent market, and the growth of the carbon-neutral fossil fuels market will no doubt be linked to whether consensus, or at least a majority view, is reached on them. This will be key to creating a credible carbon-neutral label, avoiding claims of greenwashing, and enabling comparability/fungibility of carbon-neutral products offered by different market actors.

A key question that underlies those issues is whether the carbon-neutral fossil fuels market can gain credibility and scale up through adherence to industry-driven voluntary initiatives or standards, or whether the time is now or in the near future for the market to be subject to mandatory regulation.

Market participants have only voluntary carbon-neutral standards to go on, with limited market consensus or prescription as to what the label should require and little cross-over between different types of fossil fuels. That situation typifies how other green products, such as green bonds, have tended to come to market and attract new entrants by enabling them to apply a green label without having to navigate a myriad of regulations to do so. However, as the markets for other green products have matured, the trend has shifted to a more top-down approach, whether via legislation or consensual self-regulation.

Voluntary vs. mandatory regulation: The carbon-neutral label

The voluntary framework for less carbon-intensive fossil fuels, such as LNG, is relatively well developed. Market initiatives are being developed across the globe, the most prevalent being the carbon-neutral LNG framework of the International Group of Liquefied Natural Gas Importers (GIIGNL Framework). To date, relatively few carbon-neutral LNG deals have transpired, and the development of voluntary initiatives, such as the GIIGNL Framework, is seen as one of the key stimuli for the market.

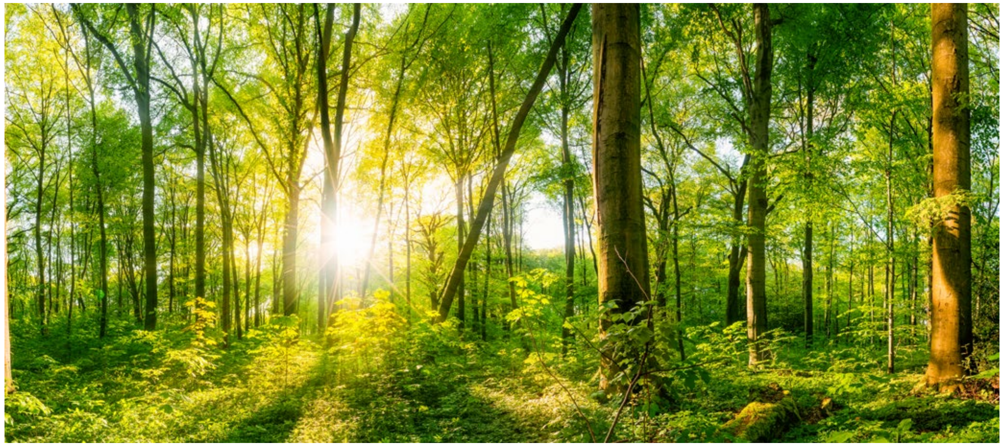
On the question of what the carbon-neutral label should require, the GIIGNL Framework caters to several decarbonization "pathways" for producers of LNG, with only one attracting the "GHG neutral" label (which requires emissions reductions at source, offsetting the balance of emissions, and a commitment to achieving long-term decarbonization). This enables LNG producers the flexibility to "opt-in" to the pathway most in accordance with their commercial aims. This is important given the potential for third-party gas suppliers and varying readiness to undergo intensive monitoring, reporting, and verification (MRV) of emissions.

By contrast, carbon-neutral voluntary initiatives for more carbon-intensive fossil fuels, such as crude oil, are significantly less developed. This is largely due to the increased offsetting costs associated with the higher carbon emissions generated from crude oil products, and the heightened complexity in measuring carbon emissions from crude oil products. As a result, to date, we lack an industry-wide voluntary framework for carbon-neutral crude oil.

Despite the absence of an established voluntary framework, crude oil transactions have been reported to be carbon neutral. One of the first "carbon-neutral" crude oil transactions is credited to have occurred in April 2021 between Lundin Energy AB and Saras S.p.A. The producer used an independent MRV certification scheme provided by Intertek Group plc in order to determine carbon emissions and, for the carbon offsetting element, sourced carbon credits certified by the VCS. The use of MRV mechanisms that are not widely recognized was criticized by commentators, and such transactions in the crude oil sector remain rare.

Calls have been made by those outside the fossil fuel industry, and some within, for governments to step in and develop a regulatory framework for carbon-neutral fossil fuels. The case from the outside is well rehearsed: calling fossil fuels carbon neutral is simply greenwashing, as they can never truly be carbon neutral by their intrinsic nature, and allowing the unregulated use of that label simply prolongs the life of the fossil fuel industry and delays the uptake of renewable alternatives. The case from within the industry is that mandatory regulation would level the playing field and may ultimately drive prices up as the ability to attach a credible, globally recognized carbon-neutral label to a cargo will add value.

It seems clear at this early stage in the development of the carbon-neutral fossil fuels market that any top-down regulation is likely to dampen the appetite for new entrants and stymie the growth of the market. Decarbonization is a relatively new concept for the fossil fuel industry and while many market actors have publicly set themselves net-zero targets, they are still developing their strategies to achieve those targets. The development of carbon-neutral products is a clear path to achieving net zero, and it is attractive at present in that it affords the flexibility to adopt an approach that aligns with a company's wider decarbonization strategy.



Voluntary vs. mandatory regulation: Carbon offsetting

Regarding the carbon offsetting aspect of carbon-neutral fossil fuel deals, the voluntary carbon market (VCM) is now reasonably well established. It has seen huge growth in recent years in the wake of the Paris Agreement and, more recently, the Glasgow Climate Pact. The growth trajectory of the VCM has been unusual in the sense that it was initially driven by top-down schemes, principally the Clean Development Mechanism (CDM) and the Joint Implementation (JI) programs operated under the UNFCCC international treaty framework. Following the collapse in prices in 2008/09 and a long period of stagnation, the recent resurgence in the VCM has been driven by a proliferation of privately operated, largely unregulated VCM offsetting programs. However, this may soon change again as Article 6 of the Paris Agreement lays the foundations for a successor scheme to the CDM that would come under the auspices of the UNFCCC.

The generally accepted standard for high-quality carbon credits is that credits must represent real, additional, verifiable, and permanent emission reductions or removals. Each of the major VCM programs has adopted that approach. However, it is worth noting that a degree of skepticism persists about the benefits of carbon offsetting and the efficacy of the VCM in reducing carbon emissions globally. In particular, critics have argued that the time lag between the emissions and the offsetting may reduce the stated effectiveness of credits and that offsetting encourages carbon leakage from one location to another rather than the overall reduction of emissions.

At a more transactional level, some still describe the VCM as the "wild west" of the carbon trading market, as it remains largely unregulated when compared to trading carbon allowances under-regulated schemes such as the EU Emissions Trading System (ETS). That is becoming less of an issue now as the market matures, thanks to various industry-led initiatives to develop governance frameworks for the VCM and standardized documentation for trading carbon credits based on the templates already widely used in the regulated carbon market.

Regarding the case for mandatory regulation in the VCM, we're already seeing examples of cross-over between the VCM and the regulated carbon market. The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) is a mandatory global framework that provides a uniform, offset-based scheme for the regulation and reduction of carbon emissions from international aviation.

Unlike existing regulated schemes, such as the EU ETS, the compliance obligations of aviation operators under the CORSIA must be met entirely through the use of carbon credits sourced from the VCM. There is no CORSIA equivalent to the EU allowance (EUA) – the regulated compliance unit under the EU ETS. The VCM has responded to the CORSIA by creating carbon credit products that specifically meet the strict eligibility criteria set out in the CORSIA rules. The VCM has also attained accreditation under the CORSIA allowing the use of those types of carbon credit by compliance entities. In turn, this has allowed the labeling of those carbon credits as being "CORSIA compliant," and such units generally trade at a premium to units that do not meet the CORSIA eligibility criteria.

The interaction between the VCM and the regulated aviation carbon offsetting scheme under the CORSIA may present a potential model for future carbon-neutral fossil fuels standards in terms of successful voluntary frameworks forming the basis of a mandatory and regulated carbon reduction scheme for fossil fuels.

The outcome for the carbon-neutral fossil fuels market could be that the unregulated VCM will continue to be unregulated and exist in parallel with the regulated carbon markets. If the carbon-neutral fossil fuels market becomes subject to regulation, then the VCM would respond to that by developing carbon credit products that, while unregulated, meet the regulatory eligibility criteria that allow their use within that regulated market. However, as noted above, it seems likely that any global approach toward regulation of the carbon-neutral fossil fuels market is some way off.

Authors

James Atkin

James works from our London office and his practice focuses on advising companies in the Oil & Gas, Energy and Infrastructure sectors with their international energy investments. Widely recognized as a leading energy lawyer and Band 1 ranked by Chambers Global, James advises clients in the energy sector on transactions in Asia, Australia, the Middle East, Africa and North America, and has extensive experience advising on large-scale energy projects, LNG sales arrangements, and energy-related mergers and acquisitions. In Chambers UK 2021, James has been described as "very knowledgeable of the industry, very easy to work with and very efficient."

Adam Hedley

Adam is a partner in the London office and has 12+ years of experience advising on a broad spectrum of UK, EU and international environmental, health & safety, product compliance, carbon market and climate change law matters. He has a particular focus on the environmental aspects of ESG, and regularly advises on key topics, such as: climate change adaptation and mitigation projects; climate-related corporate reporting; carbon offsetting and neutrality objectives; renewables and alternative/ sustainable fuels regulation, compliance and incentive schemes. He also regularly works on EU and international carbon and climate-related transactions, advisory matters and disputes, including emissions regulation, carbon trading and climate financing projects. His experience spans cap-and-trade schemes such as the EU, UK and Swiss ETS and regulatory / voluntary carbon offsetting schemes, including the UNFCCC CDM, the emerging Paris Agreement Article 6 mechanisms, CORSIA, REDD+, Gold Standard, VCS, etc. Adam is also experienced in EU renewable energy/fuel laws, and claiming/trading of UERs, RTFCs and other forms of green certificate. He has regularly been ranked as a "rising star" by *Legal 500* and as "up and coming" by *Chambers UK*.

Jake Williams

Jake is a senior associate (Australian Qualified) based in Reed Smith's London office focusing on EU, UK and international environmental, health & safety and product compliance law. Jake has experience in Australia, where he previously worked for a leading top tier environment and planning practice. He has experience in providing strategic and commercial advice to clients in a broad spectrum of sectors, including energy and natural resources, technology, infrastructure and development, chemicals, distribution and waste management. His practice involves complex regulatory and compliance advice on a broad range of environmental, health and safety compliance, approval strategies and permitting, decommissioning and remediation, sustainability, ESG and non-financial reporting, the transport of dangerous goods, the EHS aspects of corporate and real estate transactions, litigation, chemical compliance and storage, and waste management and shipping, including the transboundary movement of waste.

Proposed legislation and policy affecting GHG emissions in the U.S.

By Colette D. Honorable, Jennifer Smokelin, Debra A. Palmer and Randa Lewis

Takeaways

- Proposed rule targets Scope 3 emissions
- The SEC's final rule will probably face challenges under the APA
- U.S. federal agencies are addressing concerns over GHG emissions and climate change

On March 21, 2022, the U.S. Securities Exchange Commission (SEC) released a proposed rulemaking package to require climate-related disclosures. One such requirement relates to Scope 3 emissions.

The SEC recognizes three categories of emissions: (1) Scope 1 emissions, which are direct emissions from sources owned or controlled by a company, (2) Scope 2 emissions, which are emissions primarily resulting from the generation of electricity consumed by a company, and (3) Scope 3 emissions, which refer to "all other indirect emissions not accounted for in Scope 2 emissions," meaning emissions from sources outside a company's control. Companies are typically able to calculate Scope 1 and 2 emissions without much difficulty; however, estimating Scope 3 emissions presents challenges, as Scope 3 emissions occur from other processes and entities outside the company's control that serve the company's value chain.

Reporting under the proposed rule

For registrants that do not qualify as a smaller reporting company (SRC), the proposed rule will require disclosure of Scope 3 emissions and their intensity if they are "material" or the registrant set a GHG emissions reduction goal that includes Scope 3 emissions. Thus, the proposed rule does not require reporting of all Scope 3 emissions. A company's reporting obligation would depend on a number of specific factors, which you can read more about in our blog post here.

Scope 3 calculation methodology

Although the proposed rule adopts many features of the GHG Protocol, a key difference between the two is the proposed rule's leniency on how companies calculate GHG emissions, which includes Scope 3 emissions. The proposed rule indicates that this deviation is an opportunity for companies to choose the methodology that best suits their portfolio and financing activities.

Safe harbors

While the proposed rule introduces sweeping changes to climate-related disclosures, it also includes key provisions aimed at lessening compliance burdens, including the exemption for SRCs, discussed above, a delayed compliance start date for Scope 3 emissions reporting, and a safe harbor provision that insulates a company from certain securities law liabilities for Scope 3 emissions disclosures.

The proposal includes a safe harbor provision related to liability for Scope 3 emissions that were disclosed under the proposed rule in a document filed with the SEC. This limitation on liability would deem a Scope 3 disclosure to not be fraudulent unless it was made or reaffirmed without a reasonable basis or disclosed other than in good faith.

The proposed rule's future

The proposed rule is subject to a notice and comment period, which is set to end on June 17, 2022. During this time, the SEC will accept public comments on its proposed rule. In March 2021, the SEC requested information on climate change disclosures and received approximately 600 comments in response. The SEC will likely receive substantially more comments on the proposed rule, which it must consider and address before the rule can be finalized and enforced. This process will likely take months to complete.

The SEC's final rule, to the extent it predominantly reflects the proposed rule, will likely be challenged under the Administrative Procedure Act (APA). One possible basis for a challenge would be the Scope 3 disclosures. Industry groups will likely try to stay the regulations pending litigation by arguing that any reporting associated with Scope 3 disclosures are outside the scope of the SEC's authority or that the SEC was only permitted to require disclosure of "material" emissions.

If industry groups challenge the rule under the APA, it is possible that a court will find that the public interest and balance of equities weigh in favor of granting an injunction, just as the Louisiana district issued a preliminary injunction that barred use of the Biden administration's social cost of carbon figure.

If the final rule faces challenges in court, its implementation may well be delayed. And with the possibility of a new administration being elected for the next term, this rule faces much uncertainty.

Counting the cost of carbon

President Joseph Biden issued Executive Order 13990 immediately after his inauguration in January 2021. The executive order requires federal agencies to "capture the full costs of greenhouse gas emissions as accurately as possible, including by taking global damages into account."

Since then, U.S. federal agencies have enacted various measures to address concerns of the GHG emissions and climate change, and are facing contentious debate over how much to charge for carbon emissions.

EO 13990 established an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). The IWG defines the social cost of carbon (SCC) as the estimated cost to society of releasing one ton of carbon dioxide into the atmosphere. The SCC's value has varied from the Obama to the Trump and the Biden administrations, with the Biden administration using the Obama-era estimates adjusted for inflation. Although several states have objected to the Biden administration's use of the SCC, the U.S. Court of Appeals for the Fifth Circuit rejected the states' efforts to preclude the Biden administration's efforts (see the March 16 ruling in State of Louisiana v. Biden). There the court decided that the SCC policies may remain, because objecting states had not demonstrated standing.

The U.S. Federal Energy Regulatory Commission (FERC) and the Bureau of Land Management (BLM) are considering analyzing the SCC when issuing certificates or permits for energy infrastructure projects.

FERC is considering the issuance of a policy statement that will modify the standards used to evaluate applications by interstate natural gas pipelines to construct new facilities in order to address greenhouse gas emissions associated with the new facilities. The regulated community is weighing in.

In response to objections from numerous parties, a March 24 order reclassified two policies – the Updated Policy Statement on Certification of New Interstate Natural Gas Facilities and the interim Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews – into "draft policy statements," thereby reopening them for public comment.

But the U.S. Court of Appeals for the District of Columbia Circuit has issued a number of orders indicating that FERC must consider GHG emissions when approving proposals to construct facilities for the interstate transportation of natural gas. For example:

- *Food & Water Watch v. FERC*;
- *Vecinos Para el Bienestar de la Comunidad Costera v. FERC*; and
- *Sierra Club v. FERC*.

FERC has proposed, over the objections of certain commissioners and industry participants, to analyze not only the direct GHG effects of pipeline construction proposals, but also the upstream GHG effects associated with the production of the gas to be transported over the new facilities and the downstream GHG effects when the gas is consumed by the ultimate end-user. FERC is also considering applying the SCC to the GHG emissions that will result from new pipeline projects. FERC's proposals in this regard have been highly controversial, but it hopes to issue final rules in the near future.

Similarly, BLM has stated that it will incorporate the SCC of greenhouse gases, including carbon, nitrous oxide, and methane) into its environmental analysis of fossil fuel leasing and development on federally-owned lands. BLM has developed a report that estimates annual GHG emissions from coal, oil, and gas development on federal lands and a longer-term assessment of GHG emissions and their climate change impacts.

Authors

Colette D. Honorable

Colette leads the firm's Energy Regulatory group and is a member of the firm's executive committee. She is also a member of the firm's ESG group and is resident in the Washington, D.C., office. Colette is a highly regarded thought leader and strategist in domestic and international energy sectors. Colette recently served as Commissioner at the Federal Energy Regulatory Commission (FERC). She was nominated by President Barack Obama in August 2014, and unanimously confirmed by the U.S. Senate, serving from January 2015 until her term expired in June 2017. At the firm, Colette is a trusted advisor and counselor to several Fortune 500 energy companies, investor-owned utilities, renewable energy and technology companies. In this capacity, she provides strategic advice and counsel in a number of areas, including ratemaking matters, clean energy integration, performance-based ratemaking, achieving ESG goals and environmental justice issues. In her work, Colette supports clients working to mitigate the impacts of climate change, and also advises clients on the development and execution of inclusion strategies.

Jennifer Smokelin

Jennifer is a partner based in the Pittsburgh office. She is a thought leader on environmental and emerging energy issues, greenhouse gas legislation, and related environmental issues, with particular experience in Pennsylvania, the mid-Atlantic, California, and the European Union. Jennifer represents clients in a broad range of environmental and energy issues including environmental civil enforcement and litigation matters, as well as regulatory and transactional issues for energy and manufacturing companies. She has a particular focus on the environmental aspects of ESG, assisting clients with carbon footprint assessments, net zero plans, climate-related corporate reporting, ESG compliance, carbon offsetting and neutrality objectives, green energy, and renewables and alternative/sustainable fuels regulation.

Debra A. Palmer

Debra is based in the Washington, D.C., office. Her practice focuses on energy regulatory matters, with an emphasis on matters involving the Federal Energy Regulatory Commission (FERC), state public utility commissions, and the federal courts. She has more 30 years of experience with federal regulatory issues facing the energy industry, and has assisted her clients in pursuing their goals before FERC, state regulatory agencies, and the federal appellate courts. Debra advises clients with varied interests in the energy & natural resources sector, including natural gas companies, local distribution companies, oil and gas pipeline companies, and electric utilities. Her ability to understand regulators' goals and present her clients' interests accordingly has helped her become a leading advocate for energy firms across the United States. Deb understands the interrelationship between operational, business, and regulatory concerns faced by the energy industry. She has cultivated a deep knowledge in these areas, earning a reputation as a trusted advisor in the planning, operating, financial, regulatory and reliability issues facing the rapidly changing natural gas and electric industries.

Randa Lewis

Randa is an associate in the Pittsburgh office and focuses her practice on environmental transactions, regulations, and litigation. As part of the firm's global environmental, social and governance (ESG) practice, she advises clients on topics such as: drafting climate-related disclosures for public company filings, climate change-related risk management, renewable energy compliance matters, energy efficiency standards, and environmental sustainability issues. Randa has counseled clients on projects related to repurposing and redevelopment of traditional power sites like power plants and coal mines into renewable energy hubs.

Voluntary carbon market trading: Key risks and mitigations

By Adam Hedley and Brett Hillis

Takeaways

- No single global legal position determines the nature of voluntary carbon credits, including what title can be claimed in them and what security can be taken over them
- The lack of market standard trading documentation for voluntary carbon credits is both a hindrance to the growth of the market and an opportunity
- A two-tier voluntary carbon market labeling/pricing structure may develop: one for credits that comply with the new Paris Agreement Article 6 corresponding adjustments rules, and one for credits that do not

The voluntary carbon market (VCM) has been in operation since the 2000s, alongside mandatory/regulated carbon market schemes such as the EU Emissions Trading System and the U.S. Regional Greenhouse Gas Initiative. The two largest VCM programs, Verra's Verified Carbon Standard (VCS) and Gold Standard, have been around since 2006 and 2003 respectively. In that sense, VCM trading is nothing new. However, the VCM has only really taken off in the last few years, with the growth of the market being rapidly accelerated by the adoption of the Paris Agreement in 2016 and, in the shadows of that, the Glasgow Climate Pact in 2021 and the proliferation of governments and corporates making "net-zero" carbon reduction commitments.

The rapid growth of the VCM in recent years has made VCM trading much more mainstream. Nonetheless, because the VCM is largely unregulated, in contrast to the more established mandatory carbon markets, some commentators and participants still see it as the "wild west" of the carbon trading sector.

In this piece, we examine a few of the key issues and opportunities currently faced by the VCM.

The legal nature of voluntary carbon credits

As with any asset or legal instrument, understanding the legal nature of voluntary carbon credits (VCCs) is critical to assessing and documenting how they can be traded and what risks there are to the transacting parties, including what property interest can be claimed over them and what form of security can be taken over them. Their legal nature also impacts their regulatory treatment and what tax implications there are in trading and holding them.

Yet there remains a large degree of uncertainty over the precise legal nature of VCCs, and the VCM program providers largely skirt around this question in their rules and standards. Since a VCC is a creature of contractual law (i.e., the construct of the VCM program it is issued under) and is not an instrument that is created via any legislative or international treaty framework, its nature is determined by the law applicable to its creation, holding and transfer. It is therefore determined by national law(s), having regard to the law applicable to the contractual framework under which the relevant VCM program operates and, potentially, the governing law of any trading documentation. This will differ between VCM programs and transactions, so there is no consistent answer to the question as to the legal nature of VCCs.

Applying an English law analysis to the question, the nature of a VCC would essentially be one of either (i) a property right (in rem) or (ii) a personal right (in personam). Personal rights are generally considered nontransferable as they are so closely tied to the relationship between the obligor and the oblige, that a third party cannot require the obligor to be indebted to the third party in place of the obligee. In contrast, a property right may be enforced against the obligor by a third party if the legal processes for the transfer of the obligee's rights have been duly completed.

English law governed trading documentation generally proceeds on the basis that VCCs are a form of intangible property (although this has not been authoritatively determined by the English courts), which means legal title can be held and transferred to another party. However, as intangible property, this gives rise to complexities around what security can be taken over them. This is compounded by the need to take into account the national law applying to the VCCs and the registry account in which they are held, e.g., in the case of VCCs issued under the VCS, the law of the District of Columbia.

Industry efforts are underway to address the lack of consistency as to the legal nature of VCCs. However, until they come to fruition, it is important when trading and creating security over VCCs to assess the impact of the contractual governing law and the law applicable to the VCCs or registry account.

Standardization of trading documentation

For the same historical reasons as outlined above, in contrast to the regulated carbon markets, there is no industry standard trading documentation for VCCs. That is seen most acutely in "primary offtake" trading documentation, i.e., the first sale and purchase of VCCs from carbon reduction project owners, where documentation has tended to be project- and VCM program-specific. In such circumstances, the contractual documentation under which the VCCs will usually be traded is more similar to an emissions reduction purchase agreement (ERPA), rather than the industry documentation used to trade regulated carbon allowances such as EUAs, e.g., the template trading documentation developed by ISDA, IETA or EFET.

Even at the secondary trading stage, there is very little by way of consistent trading documentation in the market, although there are various forms out there that have their origins in trading documentation used for regulated carbon allowances, oil, metals, power and other forms of commodities or green certificates.

While there is no "magic" to documenting VCM trades, it is important to assess whether the form of contract used is appropriate to the facts of the transaction, the underlying carbon reduction project and the applicable VCM scheme, particularly in regard to primary offtake agreements. This is perhaps less of a concern with secondary spot trading, but there are still important risks/issues that merit bespoke drafting to allocate them appropriately, e.g., the Paris Agreement corresponding adjustments issue outlined below.

The lack of market standardization also presents opportunities; there is clear scope for sophisticated market actors to develop "buyer-friendly" and "seller-friendly" documentation, the scope for which is more limited when documenting trades under industry template documentation.

However, there is clearly an appetite for more standardization in the market, and there is no doubt this would benefit the many new entrants to the market who are looking to acquire VCCs to support ESG or net-zero objectives. Various industry groups (including IETA and ISDA) and working groups are developing template trading documentation, which should subsequently lead to more standardization in the approach to documenting trades in the VCM.

Paris Agreement corresponding adjustments

The long-awaited Paris Agreement Article 6 rulebook was finally approved in November 2021 after intensive negotiations over the course of the UN Climate Change Conference of the Parties in Glasgow (COP26), not to mention several years of prior talks.

The resolution of Article 6 at COP26 was seen as critical to the success of the Paris Agreement; more specifically, finalizing the Article 6 rulebook meant firming up the “corresponding adjustments” accounting rules, which would ultimately define the relationship between Paris Agreement governmental actions and the availability of carbon reductions for use in the VCM. In that regard, Article 6 was seen as both an opportunity and a threat for the VCM: the opportunity being to remove ongoing uncertainty over that relationship; the threat being that the corresponding adjustments rules could significantly reduce the scope for the VCM to operate alongside governmental climate mitigation actions, as codified in their Nationally Determined Contributions (NDCs).

The requirement to make corresponding adjustments in respect of international transfers of emissions reductions was always expected to happen; however it was unclear how far this would go. The outcome of COP26 was to extend the corresponding adjustments rules to cover emissions reductions/removals that are claimed as carbon credits under a voluntary carbon market scheme once those credits are transferred to a private/public entity located in another country. In other words, carbon emissions covered by a country’s NDC actions cannot also be claimed as VCCs under a VCM program and traded with a foreign entity, unless the government of that country confirms that it will make a corresponding adjustment to take those underlying carbon emissions outside of its NDC reporting.

The VCM program operators have had to evaluate how to factor this into their rules. Initially, the two main program providers – Verra and Gold Standard – indicated they were going in two different directions. Verra took a stance that the corresponding adjustments requirements would ultimately not affect whether VCCs could be issued, but instead what label/claim could be attached to them: an offset label (for Article 6 compliant units) or an impact label (for non-Article 6 compliant units). Gold Standard initially indicated it would take a more resolute stance by only issuing VCCs where it was demonstrated that corresponding adjustments had been made, where required. However, following a consultation it appears that Gold Standard has softened its stance, bringing it more in line with Verra.

It remains to be seen how the VCM will be impacted by all this, but it seems likely that a two-tier market/pricing structure will develop: one for VCCs that comply with Article 6, and one for VCCs that do not.

Authors

Adam Hedley

Adam is a partner in the London office and has 12+ years of experience advising on a broad spectrum of UK, EU and international environmental, health & safety, product compliance, carbon market and climate change law matters. He has a particular focus on the environmental aspects of ESG, and regularly advises on key topics, such as: climate change adaptation and mitigation projects; climate-related corporate reporting; carbon offsetting and neutrality objectives; renewables and alternative/sustainable fuels regulation, compliance and incentive schemes. He also regularly works on EU and international carbon and climate-related transactions, advisory matters and disputes, including emissions regulation, carbon trading and climate financing projects. His experience spans cap-and-trade schemes such as the EU, UK and Swiss ETS and regulatory / voluntary carbon offsetting schemes, including the UNFCCC CDM, the emerging Paris Agreement Article 6 mechanisms, CORSIA, REDD+, Gold Standard, VCS, etc. Adam is also experienced in EU renewable energy/fuel laws, and claiming/trading of UERs, RTFCs and other forms of green certificate. He has regularly been ranked as a “rising star” by *Legal 500* and as “up and coming” by *Chambers UK*.

Brett Hillis

Brett is a partner in the London office and focuses on energy and carbon trading and derivatives, and has a broad regulatory and transactional practice including financial regulatory advice, energy, carbon and commodities trading and derivatives, commodities, carbon and energy structured transactions, financial sanctions, market infrastructure and Fintech, especially in the wholesale financial and commodities markets. On the transactional side, Brett has particular experience in helping clients to structure and document transactions where regulatory constraints and other limiting requirements are particularly intense or rapidly evolving. Brett advises on complex commodity derivatives transactions, exchange-traded commodity products (ETPs) relating to a wide range of underlyings including cryptocurrencies, precious metals and emissions allowances, energy management services arrangements, tolling agreements, structured energy supply transactions, renewable energy development and transfers of commodity-related assets and businesses, including transfers of gas, power, metals, emissions and LNG portfolios. Brett is part of the firm’s global environmental, social and governance (ESG) practice. He has a particular focus on the climate change aspects of ESG and regularly advises on key topics such as carbon and other emissions trading; carbon offsetting and neutrality objectives; and the claiming/trading of a wide variety of green certificates.

Where the energy transition is surging ahead: New York State

By Peter Trimarchi

Takeaways

- New York has already begun implementing comprehensive measures to decarbonize its entire economy
- Everyone doing business in New York should understand how that transition will affect their industry
- Those who understand the new regulatory environment can enjoy competitive advantages and avoid making bad investment decisions

The process of transitioning western economies from fossil fuel-based resources to renewable ones is happening unevenly. Most transition activities have been driven largely by private project developers, corporate environmental, social and governance (ESG) policies, or aspirational national and state-level “goals,” often with little teeth to them. Such actions are also largely focused solely on electricity generation, without addressing other sectors of the economy that use fossil fuels for energy, such as transportation and manufacturing.

Some places, however, are undertaking comprehensive actions to fully decarbonize their economies, backed by statutory mandates that will force the action to occur. The State of New York is one of those places. As described below, New York has passed comprehensive legislation requiring a true energy transition to occur in the state over the next 20 to 30 years. As New York now labors through the process of drafting regulations to make that vision a reality, it offers a window into how other jurisdictions can make similar changes, and how business and industry will need to adapt to a radically different economy in the not-too-distant future.

In 2019, New York passed the Climate Leadership and Community Protection Act (CLCPA), which establishes aggressive limitations on carbon emissions from all sectors of the economy. While it does predictably call for 100 percent of the state’s electricity generation to come from zero-emission sources by 2040, it also requires an 85 percent reduction in all greenhouse gas emissions statewide, from whatever source, by 2050. Importantly, the CLCPA defines statewide greenhouse gas emissions to include not just sources within the state, but also greenhouse gases produced outside the state for imported electricity or the extraction and transmission of fossil fuels imported into the state.

Clearly, those are remarkably ambitious requirements to be achieved in a very short period of time, which, of course, begs the question of how the state will actually do it. While it would be easy to assume that the requirements could be satisfied primarily through a shift to 100 percent renewable energy production, this is not true – electricity production actually accounts for a relatively small percentage of statewide greenhouse gas emissions. The state Department of Environmental Conservation (DEC) has determined that the state's greenhouse gas emissions are currently generated from buildings (32 percent), transportation (28 percent), electricity (13 percent), waste (12 percent), industry (9 percent), and agriculture (6 percent). Those numbers demonstrate that a truly comprehensive energy transition will require far more than just the installation of solar panels and wind farms.

The CLCPA lays out how the state will implement its strict mandates. First, by 2023 a Climate Action Council, made up of the heads of various state agencies and other members, must develop a Scoping Plan which will provide recommendations for achieving the required emissions limits (including regulatory measures). The Council issued a draft Scoping Plan in December 2021, which is now available for public comment. The CLCPA then charges DEC and other state agencies with issuing binding regulations by January 1, 2024, which will implement measures to achieve the required emissions reductions.

The magnitude of the changes the CLCPA will require is evident in the draft Scoping Plan issued by the Climate Action Council. Within its 331 pages, the draft Scoping Plan calls for some truly disruptive actions that will be required to achieve the reductions called for by the CLCPA. Some of these include (a) a price on greenhouse gas emissions; (b) elimination of natural gas as a fuel source for new single and multi-family homes by 2024 and 2027, respectively; (c) a requirement that all light-duty vehicles and 40 percent of medium- and heavy-duty vehicles sold in the state be zero-emission by 2030; and (d) capture or elimination of methane sources from waste, agriculture, and energy sectors. The Scoping Plan calls for the electrification of almost all aspects of the residential, manufacturing, and transportation sectors of the economy, and reliance on renewable energy sources for that electricity. Such reliance on electrification is so significant, in fact, that New York's peak electric load is expected to flip from a summer peaking system to a winter peaking system, due to the electrification of so many heating systems and the reduced performance of electric vehicle battery systems in winter months.

Although the final implementing regulations are not due until January 1, 2024, state agencies and the Legislature are not simply waiting around to see how they turn out. Both are actively taking measures on their own to ensure that new actions are consistent with the goals of the CLCPA. As just two examples, the DEC is now requiring all applications for new air emissions permits to include a discussion of how the permittee's operations will be consistent with the goals of the CLCPA, and the Legislature recently sent a bill to the Governor's desk for signature that imposes a two-year moratorium on the issuance (or renewal) of air permits to power plants that sell power to certain cryptocurrency mining operations.

The CLCPA's far-reaching impacts are thus already affecting businesses in New York, and will fundamentally change the way business is conducted in New York over the next three decades. Companies with operations in the state, or with plans to expand there, must pay very close attention to the future actions of the Climate Action Council and state regulatory authorities, to determine how proposed future actions will affect their industries. They should also strongly consider participating in the regulatory process, to help shape the final rules to the greatest extent possible.

Author

Peter Trimarchi

Peter is a partner in the New York office and counsels clients in all aspects of environmental law, particularly in transactional matters, including financing and development of renewable energy projects. He helps clients manage environmental risks and permitting challenges in the most efficient manner possible, and helps them take advantage of opportunities in a complex and ever evolving regulatory landscape. If the need arises, Peter also represents clients in enforcement proceedings and environmental litigation matters. A large part of Peter's practice is in the project development space. He helps project developers obtain environmental and land use permits for solar and wind projects, natural gas facilities, and other energy and infrastructure projects. He also assists lenders with the detailed environmental and permitting due diligence required for complex project finance transactions. With the recent boom in solar PV systems in New York, Peter has gained significant experience assisting clients in the development and financing of those systems. He helps clients understand and comply with relevant orders of the New York Public Service Commission and the NY-Sun incentive program, identify and obtain required state and local permits, and purchase and sell individual projects or portfolios of projects throughout the state and beyond. He also has extensive experience in the New York community solar market, representing companies soliciting and managing both anchor customers and mass market customers to be assigned to a community solar project.

CHAPTER 02

‘Cleaning up’ of tomorrow’s alternative fuels

LNG marine bunkers' role in the transition to cleaner shipping

By Kevin Keenan, Antonia Panayides and Ella Evagora

Takeaways

- Shipping has a target of net-zero CO_2 emissions by 2050; restrictions will ensue
- Demand for LNG-powered ships has increased greatly
- LNG has clear environmental and commercial benefits for shipping
- In spite of the Ukraine/Russia crisis, LNG bunkering looks poised to grow

The shipping industry is facing increased regulation in a move to a greener shipping emissions profile. Regulations on shipping emissions are increasing, with the International Maritime Organization (IMO) setting a 2030 target for emissions reductions, and signatories to a September 2021 Global Methane Pledge will try to lower 2020 methane emissions levels by 30 percent by 2030.

These goals are aimed at mapping the way to net-zero CO2 emissions by 2050. With these policy commitments in mind, and with shipping companies on their own seeking to reduce greenhouse gas emissions and reap other clear benefits that LNG bunkering affords, there has been a significant increase in demand for LNG bunkers. This is evidenced by multiple shipbuilders building LNG bunker vessels, multiple shipowners ordering the construction of LNG-fueled vessels and a number of shipping companies exploring options for sources of green fuel production. Some examples of these trends include the following:

- Orders for new LNG-fueled ships reached record highs in 2021. According to data from Det Norske Veritas (DNV), there was a net increase of 240 ships from the previous year, a bigger increase than in the previous four years combined. This trend did not let up in early 2022, with DNV reporting that another 40 ships powered by LNG were ordered in January 2022 alone.
- Japanese shipbuilder, Mitsubishi Shipbuilding, a part of Mitsubishi Heavy Industries, will build an LNG bunker vessel, the first to operate in the waters off western Japan.
- Maersk and Egyptian authorities have signed a partnership agreement to explore the establishment of green fuel production in Egypt.

This article explores the reasons for the increased demand for LNG–fueled vessels and whether LNG is the way forward for clean shipping.

Reasons for increased demand for LNG fuel

a. Increased regulation – Net-zero 2050 target

IMO rules from 2020 (IMO 2020) lower the sulfur content of bunker fuel to 0.5 percent (down from 3.5 percent) mass by mass (m/m). To comply with this, vessels must switch to fuels that are low in sulfur content or install a fuel cleaning method to reduce the sulfur content of traditional bunker fuels. The sulfur oxides regulation (MARPOL Annex VI, regulation 14) applies to all ships, whether they are on international voyages or domestic voyages, solely within the waters of a country that is party to MARPOL Annex VI. Enforcement of IMO 2020 is supported by a ban on the carriage of non-compliant fuel which has been in effect since March 1, 2020. The ban prohibits ships from carrying fuel with a sulfur content higher than 0.5 percent in their fuel tanks. It is noteworthy that port state control authorities do not have to prove consumption of a non-compliant fuel; they simply have to find its presence in a ship’s tanks to establish a violation. The only exception to this standard is ships equipped with exhaust gas cleaning systems (scrubbers) that remove sulfur emissions from a ship’s exhaust before the gas is released into the atmosphere. In considering the aim for net-zero by 2050, DNV Germanischer Lloyd confirmed in its 2050 Marine Energy Forecast that “[i]n almost any scenario, LNG will be the single most important fuel in the market.” Further, regulations on shipping emissions are set to get stricter. Following the 2021 UN Climate Change Conference (COP26), the IMO 2030 emissions target will now be reviewed in 2022. Also, following COP26, signatories to a Global Methane Pledge will see countries seek to lower 2020 methane emissions levels by 30 percent by 2030.

Increased regulation greatly increases the potential for a vessel’s carbon footprint to be penalized in the new framework. However, with the clear benefits of LNG fuel, vessels will be placed in a good position to comply with the incoming regulations.

The benefits of LNG are discussed below.

b. Clear environmental and commercial benefits

LNG is one of the cleanest marine fuels available and has significantly lower CO_2 emissions than heavy fuel oil, marine diesel oil or marine gas oil. Moreover, LNG provides higher energy content and lower operational and maintenance costs. LNG is suitable for ferries, passenger ships, tankers, bulk carriers, supply ships and containerships. LNG can significantly reduce pollution from nitrogen oxides (NOx) and particulate matter compared with conventional marine fuels while cutting emissions of sulfur oxides (SOx) by more than 90 percent, helping significantly to meet regulatory requirements. Additionally, LNG can reduce greenhouse gas emissions by up to 23 percent compared with traditional marine fuels, depending on the engine used.

c. Future-proof (cost, reliability and increase in infrastructure)

The reliable long-term supply of natural gas is also a key factor in LNG being more feasible in the long term than current fuels. The safe refueling of LNG-powered ships and the safe evacuation of LNG fuel from ships in an emergency are of paramount importance for the protection of LNG as a commercially viable and acceptable marine fuel. LNG has the potential to be decarbonized further using “drop in” bio gas-sourced LNG (bioLNG) and, in the future, synthetic sources of methane.

Melissa Williams, vice president of Shell Marine, believes that for owners who support decarbonization and are in the market for new build vessels, “the only tangible new product and the best option is LNG.” Williams told *Trade Winds* that “this is another industrial revolution happening right in front of us and most people don’t even realize. […] We are changing a culture not just within the company but within society. If owners have to make a decision to put something on the water and really believe in decarbonization, then LNG is the lower-carbon option than the alternatives.”

Writing in *The Maritime Executive*, Peter Keller, chairman of SEA-LNG, a multi-sector industry coalition established to demonstrate LNG’s benefits as a viable marine fuel, commented: “LNG demand, availability and infrastructure are all growing rapidly. LNG can be bunkered at most key ports today, including major marine fuel bunkering hubs such as the Port of Singapore and Rotterdam.” Keller asserts that this will soon apply to bioLNG as well: “Carbon-neutral bioLNG can be bunkered into existing fuel tanks and blended with traditional LNG with no changes required to the vessel or any of its operating systems/procedures. This ability to drop in bioLNG, and in the longer-term renewable synthetic LNG, ensures that LNG-fueled vessels are future-proof assets. Meanwhile, the option to blend bioLNG with traditional LNG allows ship operators to incrementally introduce the lower carbon fuel in line with availability and increasingly stringent emissions requirements.”

Obstacles to overcome

a. Price spikes due to supply and demand

Natural gas prices remained volatile throughout 2021, reaching record highs in Europe in October, owing to rising demand and supply constraints, exacerbated by declining storage volumes. The volatility emphasizes the need for a more strategic approach to achieving a secure, reliable and flexible gas supply in the future to avoid exposure to price spikes. Jerome Leprince-Ringuet, managing director of TotalEnergies Marine Fuels, acknowledged in the latter half of 2021 that the price of LNG was higher than gasoil or VLSFO (very low sulfur fuel oil), but noted that vessels having dual-fuel engines can hedge between the two markets. Also, Leprince-Ringuet told *Trade Winds* he is confident that the supply-demand balance will ease in the months to come.

b. Ukraine/Russia crisis: Does it impact where LNG can be sourced from?

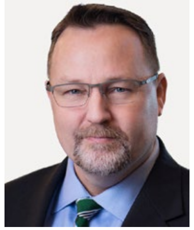
In response to the Russian invasion of Ukraine, the United States is banning all Russian oil and gas imports and the UK will phase out Russian oil imports by the end of 2022. The United States and the EU have announced a deal on LNG in an attempt to reduce Europe's reliance on Russian energy. The deal will see the United States provide the EU with extra gas, equivalent to around 10 percent of the gas it currently gets from Russia, by the end of 2022. A term of the new deal will see the United States and other countries supply an extra 15 billion cubic meters of gas in addition to 2021's 22 billion cubic meters. Reducing reliance on Russian oil and gas will require sourcing imports from non-Russian suppliers. New supplies of gas, will have to come from alternative places. However, there is already competition for LNG supplies from the world's largest producers, Qatar, Australia, and the United States, as well as other, smaller but nonetheless important producers, and that has been pushing prices up. The biggest producer of LNG in the United States, Cheniere Energy, warns of challenges ahead for European consumers, with limited new supplies scheduled to hit the market. Plans for Europe to phase out its reliance on Russian natural gas will be complicated by intractable, lengthy construction times for new LNG infrastructure.

Conclusion – LNG bunkering is the way forward for cleaner shipping

While carbon-zero technologies such as hydrogen show some promise for carbon-free shipping at some point in the future, the most readily available solution to decarbonizing the shipping industry in the near to medium term is LNG. LNG is not only greener than traditional bunker fuels, it is also cheaper and more economical, although that doesn't account for the investment that needs to be made to bring LNG bunkering into the mainstream. Some investment has been made, but more will be required in order to see LNG bunkering proliferate to the extent needed to offset traditional bunker fuels. The advent of new and stricter regulations is certainly one driver for some of that investment; the cost savings and lower maintenance costs associated with burning LNG for propulsion are another. Only time will tell whether those two drivers will be enough to bring about a new revolution in marine emissions.

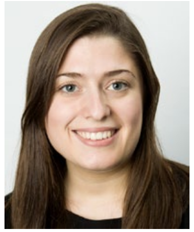
Authors

Kevin Keenan



Based in our Houston office, with a global practice focused on energy transportation and infrastructure development, Kevin advises clients on transactions across the energy value chain. For more than 25 years, Kevin has helped clients with large-scale capital projects in more than 30 countries, including in the LNG sector where he has taken the lead outside counsel role in dozens of liquefaction, shipping and regasification projects globally. In the LNG shipping space, Kevin has been at the forefront of the development of contract structures for the construction and chartering of multiple floating storage and regasification units (FSRUs), floating storage and regasification barges (FSRBs), floating storage units (FSUs), along with conventional LNG carriers, tugs and barges. Kevin has helped clients around the world acquire more than 80 conventional LNG carriers under long-term charters, and build more than 60 LNG carriers under bespoke shipbuilding contracts with South Korean, Japanese, Chinese, and European shipyards. Kevin is frequently listed among the world's premier lawyers in Chambers Global, Chambers USA, Chambers Latin America, The Legal 500 USA, The Legal 500 Latin America, Expert Guides (The World's Leading Lawyers), and Who's Who Legal.

Antonia Panayides



Based in our London office, Antonia is a partner in Reed Smith's Transportation Industry Group. She deals with a wide range of contractual offshore and shipping matters. Antonia advises clients on offshore wind projects, specifically in respect of charters for support vessels involved in the wind project. Her experience also includes shipping/LNG charterparty, shipbuilding and sale and purchase disputes in relation to both High Court and arbitration proceedings. Antonia acts for owners, charterers, managers and brokers as well as P&I and defence clubs. Antonia advises clients in relation to new decarbonization regulations and clauses to be used in contracts to address decarbonization.

Ella Evagora

Ella is a trainee in the London office in our Transportation Group, sitting in dry shipping litigation. Ella joined the firm in 2021 and has previously sat in our Financial Industry Group in Structured Finance and has been on a client secondment to Bauer Media. Ella has assisted clients with complex commercial disputes and has non-contentious experience which involved drafting and negotiating bespoke agreements for clients.

U.S. ramps up LNG exports in response to invasion of Ukraine

By Colette D. Honorable and Debra A. Palmer

Takeaways

- The United States became the largest exporter of LNG in 2021
- It will attempt to increase LNG exports to the EU by 15 bcm in 2022 to reduce EU dependence on Russian oil and natural gas
- The United States and the EU Commission agreed cut overall demand for natural gas by deploying clean energy measures

The United States became the world's largest producer of LNG in 2021, at a time of increased European demand for LNG. Europe's need for LNG increased due to reduced purchases of fossil fuels from Russia following Russia's invasion of Ukraine and the imposition of economic sanctions on Russia. The United States and the European Commission reached an agreement on March 25, 2022, under which the United States will strive to increase LNG deliveries to Europe by 15 bcm this year and further increase LNG volumes in future years.

Expanded U.S. LNG exports will replace about 30 percent of the LNG that EU countries previously imported from Russia. At the same time, the United States and the European Commission agreed to try to reduce the greenhouse gas intensity of LNG infrastructure and overall demand for natural gas, by deploying clean energy measures.

The United States has greatly increased its ability to export LNG in recent years. On April 27, 2022, the U.S. Department of Energy (DOE) granted increased export authorizations to two LNG export projects. The DOE's orders allow Golden Pass LNG to export an additional 0.35 bcf per day of LNG and Magnolia LNG to export an additional 0.15 bcf per day, to any country not specifically prohibited by U.S. law or policy.

The U.S. Energy Information Administration (EIA) predicted in April 2022 that the United States will export 12.19 bcf per day of LNG this year, up from 9.76 bcf per day in 2021. The EIA also predicted that U.S. LNG exports will further increase to 12.64 bcf per day in 2023. EIA estimates have been increasing – its March 2022 prediction was that the United States would export 11.34 bcf per day of LNG in 2022.

Currently, the United States has eight operational LNG export facilities with a capacity of more than 13 bcf per day, with three others under construction that will expand capacity by more than 6.5 bcf per day. The Federal Energy Regulatory Commission (FERC) has approved an additional 12 export facilities with a total capacity of about 21.6 bcf per day, but the project sponsors have not yet started construction on these. FERC is considering applications filed by project sponsors to construct and operate seven more export facilities, with two others in the pre-filing stage at FERC. U.S. LNG export capability has increased dramatically since 2016, when it had almost no LNG export capability, permitting the United States to become the largest exporter of LNG over a five-year period.

U.S. LNG exports are very near their limit with current infrastructure. About 98 percent of available liquefaction capacity was in use in the fourth quarter of 2021, underscoring the need for project sponsors to move forward with construction of additional LNG export facilities.

Environmental groups have expressed concerns that the increase in the U.S. LNG industry, given that natural gas is a fossil fuel, may contribute to climate change. The March 2022 agreement between the United States and the European Commission recognizes these concerns by requiring the countries to implement clean energy initiatives to reduce overall natural gas consumption. The Russian invasion of Ukraine, however, clearly has made it likely that LNG exports from the United States will remain high.

Authors

Colette D. Honorable

Colette leads the firm’s Energy Regulatory group and is a member of the firm’s executive committee. She is also a member of the firm’s ESG group and is resident in the Washington, D.C., office. Colette is a highly regarded thought leader and strategist in domestic and international energy sectors. Colette recently served as Commissioner at the Federal Energy Regulatory Commission (FERC). She was nominated by President Barack Obama in August 2014, and unanimously confirmed by the U.S. Senate, serving from January 2015 until her term expired in June 2017. At the firm, Colette is a trusted advisor and counselor to several Fortune 500 energy companies, investor-owned utilities, renewable energy and technology companies. In this capacity, she provides strategic advice and counsel in a number of areas, including ratemaking matters, clean energy integration, performance-based ratemaking, achieving ESG goals and environmental justice issues. In her work, Colette supports clients working to mitigate the impacts of climate change, and also advises clients on the development and execution of inclusion strategies.

Debra A. Palmer

Debra is based in the Washington, D.C., office. Her practice focuses on energy regulatory matters, with an emphasis on matters involving the Federal Energy Regulatory Commission (FERC), state public utility commissions, and the federal courts. She has more 30 years of experience with federal regulatory issues facing the energy industry, and has assisted her clients in pursuing their goals before FERC, state regulatory agencies, and the federal appellate courts. Debra advises clients with varied interests in the energy & natural resources sector, including natural gas companies, local distribution companies, oil and gas pipeline companies, and electric utilities. Her ability to understand regulators’ goals and present her clients’ interests accordingly has helped her become a leading advocate for energy firms across the United States. Deb understands the interrelationship between operational, business, and regulatory concerns faced by the energy industry. She has cultivated a deep knowledge in these areas, earning a reputation as a trusted advisor in the planning, operating, financial, regulatory and reliability issues facing the rapidly changing natural gas and electric industries.

The nuclear new build renaissance: Challenges and opportunities

By Peter Rosher, Liam Hart and Vanessa Thieffry

Takeaways

- French and UK governments plan to build new nuclear power plants
- Post-Fukushima hiatus now over as nations must expand zero-carbon electricity
- Global nuclear supply chain has significant opportunities

France and the United Kingdom have renewed their focus on the completion of nuclear new build projects. In this article, we explore why this nuclear renaissance is happening and the obstacles and opportunities it faces. We also look at nuclear energy in Germany and the challenges faced by Russian-related projects in the wake of the war in Ukraine.

France and the UK: Different historical approaches to nuclear energy

Nuclear power has historically been a flagship of French industry, and today France operates 56 civil reactors. Approximately 70 percent of French electricity is produced using nuclear power, and France is also the world's largest net exporter of electricity, in large part thanks to its nuclear generation capacity. Despite this, the administration of President François Hollande passed a law after the Fukushima accident in 2011 to reduce nuclear-generated electricity to 50 percent of the whole in France by 2025, although industry was not compelled to carry out the reductions. In the early years of the Macron administration, after 2017, the government was also somewhat ambivalent about the future of nuclear energy because, among other concerns, many of France's nuclear plants were aging and it would take time to bring new reactors into operation.

Although the United Kingdom was the first country to harness nuclear energy for civil power generation, the UK allowed aspects of its nuclear new build construction capability to decline significantly during the 1990s. The UK now has 11 operating reactors, generating approximately 15 percent of the country's electricity, down from the late 1990s high point of approximately 25 percent.

Germany cuts nuclear in response to Fukushima

Germany has considerable recent expertise in nuclear engineering and new build construction relating to plants outside Germany. However, in 2011, in response to Fukushima, Germany decreed that it would abandon domestic nuclear energy completely by the end of 2022. At that time, Germany was generating nearly a quarter of its electricity from nuclear energy and had 17 reactors. Germany's policy shift led Vattenfall (a Swedish state-owned power company) to start an arbitration against Germany under the Energy Charter Treaty regarding Vattenfall's interest in two German plants earmarked for closure and to simultaneously challenge the policy in the German courts. It was announced in March 2022 that the German government would pay €1.4 billion to Vattenfall to settle those claims, with additional smaller payments to three German energy companies that were also affected by Germany's decision to phase out nuclear power.

Nuclear new build renaissance in France and the UK

After Fukushima, the future of nuclear energy looked relatively unpromising in much of Europe. But in the last two years, French and UK attitudes toward nuclear energy have changed dramatically, particularly in the last few months. There are three main reasons for this:

1. The climate crisis and the importance of reaching zero carbon as quickly as possible are reviving the fortunes of nuclear as a "green" – or at least, transitional – source of energy. This is reflected in the EU Commission's decision in February 2022 to classify certain nuclear activities as supporting the transition to a climate-neutral economy.

2. The war in Ukraine has resulted in sanctions against Russia and the broader political realization that European states are overly reliant on Russian gas.

3. The economic impact of COVID-19 has encouraged governments to look more favorably on major infrastructure investment as a way of promoting economic recovery.

In light of the above, France envisages the commissioning of up to 14 new EPR reactors by 2050, as well as prolonging the life of existing reactors where possible.

The UK government released its Energy Security Strategy on April 7, 2022, unveiling plans to increase nuclear power generation to 24GW by 2050 – three times more than now and once again representing up to a quarter of projected electricity demand. The government anticipates that could spur the nuclear sector into building up to eight more reactors across the next series of new build projects. This comes in addition to the new build plant currently under construction at Hinkley Point C.

Looking forward: Opportunities and challenges

The renewed focus on nuclear new build projects in the UK and France opens up several opportunities and challenges.

It goes without saying that the nuclear and construction industries will prosper in countries where nuclear mega-projects do receive the green light. However, considerable investment in upskilling and additional capacity will be required if multiple projects are to be completed simultaneously.

In the UK, the experience developed in the construction of Hinkley Point C will be invaluable, particularly for the Sizewell C project, which uses the same EPR design. The EPR design will also be used in the proposed new French reactors, applying lessons learned on previous projects. The global nuclear supply chain could potentially experience a boom in demand for materials and services, with the potential for associated bottlenecks and delays.

The UK government's ambitious plans depend in some part on the success of its recent decision to change the preferred financing model to a Regulated Asset Base (RAB) model. Under the RAB model, a company receives a license from an economic regulator to charge a regulated price to consumers in exchange for providing the nuclear plant. The RAB model differs from previously preferred Contract for Difference (CfD) approach, under which the developer agreed to pay the entire cost of constructing the nuclear plant in return for an agreed fixed price (the "strike price") for electricity output once the plant is online. Unlike the CfD model, where construction risk sits with the developer, the RAB model shares the risk between investors and consumers, while also maintaining the incentives for the private sector to minimize the risk of cost and schedule overruns. The fact that CfD placed the entire construction risk on developers has led to the cancellation, in recent years, of several potential nuclear projects in the UK.

In France, it remains to be seen whether the EU Commission's decision to classify nuclear energy as a transitional activity will survive potential legal challenges, and what effect that will have on the investment environment.

In contrast to projects in the UK and France, the Ukraine crisis has the potential to negatively impact Russian-related nuclear projects. Russia has been a key exporter and financer of nuclear projects, often backed by cheap Russian loans. Rosatom, a Russian state-owned corporation, is currently building or was planning to build plants in Turkey, Hungary, Belarus, Finland, Egypt, China, India and Bangladesh. However, following recent events, Rosatom's Finnish new build project has been suspended, and the planned expansion of the Paks II nuclear plant in Hungary may also be affected. It may be that the previous Russian nuclear export success story suffers more broadly in the face of current or future sanctions.

Despite these issues, these are exciting times to be involved in the nuclear industry, and the nuclear renaissance has the potential to transform electricity production on the way to a carbon-neutral future.

Authors

Peter Rosher

Peter is global chair of Reed Smith’s International Arbitration group and based in the Paris office. He is a dual-qualified (English solicitor/French avocat) lawyer, with a particular experience in international arbitration and dispute resolution, including dispute boards and adjudications. Peter has specific experience in the field of energy (oil, gas, nuclear, mining, hydro, wind, solar) in many jurisdictions across Europe, Asia, the Middle East and Africa and involving all major standard form construction contracts (including FIDIC, NEC and IChemE). He also provides strategic project advice and acts as project counsel, assisting clients (owners, contractors and sub-contractors) to monitor, manage and minimize risk on claims and disputes throughout the project lifespan. He is consistently recognized by all leading directories as for his experience in construction and energy cases.

Liam Hart

Liam is a senior associate in the London office at Reed Smith focusing on projects and construction. Liam assists clients with all types of construction project advisory and dispute matters in the energy space in the United Kingdom and globally. Liam has advised owners, contractors, subcontractors and consultants on major energy projects throughout the world, including with respect to nuclear new build plants, nuclear maintenance projects, onshore and offshore wind, solar, downstream oil and gas, and conventional power plants. He has substantial experience with FIDIC, NEC, IChemE, and various other standard form construction contracts, and with all of the major institutional arbitration rules, expert determination, dispute boards and in domestic and international litigation.

Vanessa Thieffry

Vanessa is a senior associate in the firm’s Energy & Natural Resources Group based in Paris. Vanessa’s practice focuses on the resolution of technical disputes, notably in the infrastructure and construction sectors, and/or involving an environmental or environmental, social and governance (ESG) component. Vanessa recurrently assists clients of the energy industry on their oil and gas, wind, hydro, and nuclear domestic and international projects (contracts and claims management), and dispute resolution thereof, including pipeline rehabilitations, new build plants, and nuclear maintenance operations. Vanessa has acted as counsel, arbitrator, and secretary to arbitrators in over 30 arbitration procedures

CHAPTER 03

Hydrogen in tomorrow's world: Destination or aspiration?

Hydrogen regulations by jurisdiction and changing transmission systems

By Nicolas Borda, Simone Goligorsky, Simon Grieser, Colette D. Honorable, Eric Lin, Adela Mues, Debra A. Palmer, Hagen Rooke, Nicolas Walker, Karim Alhassan, Albertine Aquenin, Nicole Cheung, Tufayel Hussain, Zahir Sabur and Ievgeniia Burkhart

Takeaways

- Germany is using a stop-gap regulatory framework until EU rules take effect
- Separate rules for hydrogen and natural gas transmission are inevitable
- Many countries use existing gas legislation to regulate hydrogen
- Land constraints may prevent some countries from producing green hydrogen

In this article, we look at the regulations in some of the key jurisdictions globally, which includes: European Union, France, Germany, the United Kingdom, China, Singapore, the United Arab Emirates, and the United States, In the last two years, legislators have stepped up their efforts by launching hydrogen strategies.

The climate crisis has become a central policy driver in many jurisdictions, with regulators coming to the view that clean hydrogen may provide the necessary solution to reach the targeted levels of decarbonization, as set out in international treaties such as the Paris Agreement, and as discussed at COP26. Consequently, stakeholders, including industry players, investors, supranational organizations, and governments, have begun harnessing the potential of hydrogen to drive the global green energy transition, creating a hydrogen policy momentum.

Ahead of the development and implementation of product-specific legislation, regulators in many of these jurisdictions have brought hydrogen within the scope of existing laws (for example, those applicable to natural gas). Alongside the use of existing laws, regulators are drafting a comprehensive regulatory framework that will govern the production, storage, transportation, distribution, and associated infrastructure of hydrogen. The forthcoming regulations also will set out rules pertaining to the use, sale, and purchase of low-carbon hydrogen.

The regulators' overarching objective is to facilitate the development and functioning of the domestic hydrogen market, as well as cross-border trade. To this end, some regulators hope to implement public support mechanisms and incentives, and to develop a workable definition of clean hydrogen, which is necessary for the establishment of a licensing regime. Some jurisdictions also are considering the launch of certification tools that provide guarantees of origin and trace the types of hydrogen produced. However, it is worth noting at the outset that, despite certain similarities, hydrogen policy strategies will differ from jurisdiction to jurisdiction. In this article, we seek to provide an overview of the legislation that is currently in place, and provide a summary of forthcoming proposals, in certain key jurisdictions.

European Union

Pressure to create a hydrogen-only distribution system

At the EU level, the only rules regulating the gas market are Directive 2009/73/EC of the European Parliament and of the Council of July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (*Gasbinnenmarktrichtlinie* – GasRL) and the Regulation of the European Parliament and of the Council on the internal markets for renewable and natural gases and for hydrogen (*Fernleitungszugangsverordnung* – ErdgasZVO).

The currently applicable versions of the GasRL and ErdgasZVO are designed to regulate the transmission, distribution, supply, and storage of natural gas.

Pending legislation

On December 15, 2021, the EU Commission published proposals for the regulation of the natural gas and hydrogen market. This would involve amending the GasRL and ErdgasZVO.

Like Germany's recently amended Energy Industry Act (Energiewirtschaftsgesetz – EnWG), both drafts make a clear distinction between the regulation of natural gas networks and that of hydrogen networks. However, unlike the EnWG, the EU regulatory requirements for hydrogen would apply to all hydrogen network operators: There is no opt-in option.

Combined gas and hydrogen operations

There are high hurdles for the combined operation of gas and hydrogen networks.

Operating gas and hydrogen networks in combination, as many transmission and distribution system operators would like to do, would be virtually impossible with the implementation of the regulations.

Definition of "gas" under GasRL and ErdgasZVO

Natural gas is referred to when the gas consists mainly of methane or can be fed into the natural gas grid and transported in a technically safe manner.

Hydrogen, on the other hand, is not defined in more detail, but this is also due to the fact that the EU follows a more technology-open approach; i.e., all production paths for hydrogen generation (electrolysis, steam reforming, methane pyrolysis, etc.) are covered.

Upcoming European Parliament and Council rules for internal market in natural gas

Definition

Under the present drafts, "gas" means not only natural gas, but also hydrogen.

The article 2 of the GasRL treats gases together and does not make an overall distinction between hydrogen and other gases, thereby defining "gases" as "hydrogen and gas."

Strengthening consumer and end-user markets

Article 10 I ensures that all end customers have the right to be supplied with gases, including hydrogen, by a supplier. This applies regardless of the member state in which the supplier is registered.

Article 10 I further stipulates that in the supply contract end customers are entitled to an overview of the services to be provided, and the various quality levels and maintenance services offered.

Article 11 gives the customer the right to change hydrogen supplier. In this context, it is stipulated that the switching fees incurred in the event of a switch must be reasonable.

Duties of hydrogen network operators, hydrogen storage facilities, and hydrogen terminals

Article 46 regulates the various duties of hydrogen network operators, hydrogen storage facilities and hydrogen terminals. Among other things, under article 46 I a), a safe and reliable infrastructure for the transportation and storage of hydrogen must be operated, maintained, and further developed.

It further provides that environmental protection must be taken into account and close cooperation must be established with associated and neighbouring hydrogen network operators.

In addition, under article 46 I b), operators must ensure that the hydrogen system can meet a realistic demand for the transportation and storage of hydrogen.

Also, under article 46 I f), operators must provide network users with the information they need for timely access to the infrastructure.

Article 52 I obliges operators of hydrogen networks to send the regulatory authorities, at regular intervals, details of the hydrogen infrastructure that they plan to build.

It should be noted that, as an EU directive, these regulations do not enter into force immediately upon their adoption, but must first be transposed by member states into national law.

Overview of the European Parliament and ErdgasZVO rules

Third-party access

Under article 6 I of the ErdgasZVO, hydrogen network operators must offer their services to all network users on a non-discriminatory basis. If the same service is offered to different customers, equivalent contractual conditions apply. Hydrogen network operators must also publish on their website the contract terms and conditions, the tariffs charged for network access and, where applicable, the balancing charges.

Distribution of capacity rights

Capacity rights for hydrogen storage and distribution should be freely tradable. To this end, article 11 requires each transmission system operator, storage system operator, LNG system operator, and hydrogen system operator to take appropriate measures to ensure that capacity rights can be traded freely, transparently, and in a non-discriminatory manner.

Obligation of hydrogen plant operators

In accordance with article 31 I, hydrogen storage operators must publish details of all services they offer, including the relevant terms and conditions, and the technical information required by hydrogen storage users. Regulatory authorities may require operators to publish additional information for network users.

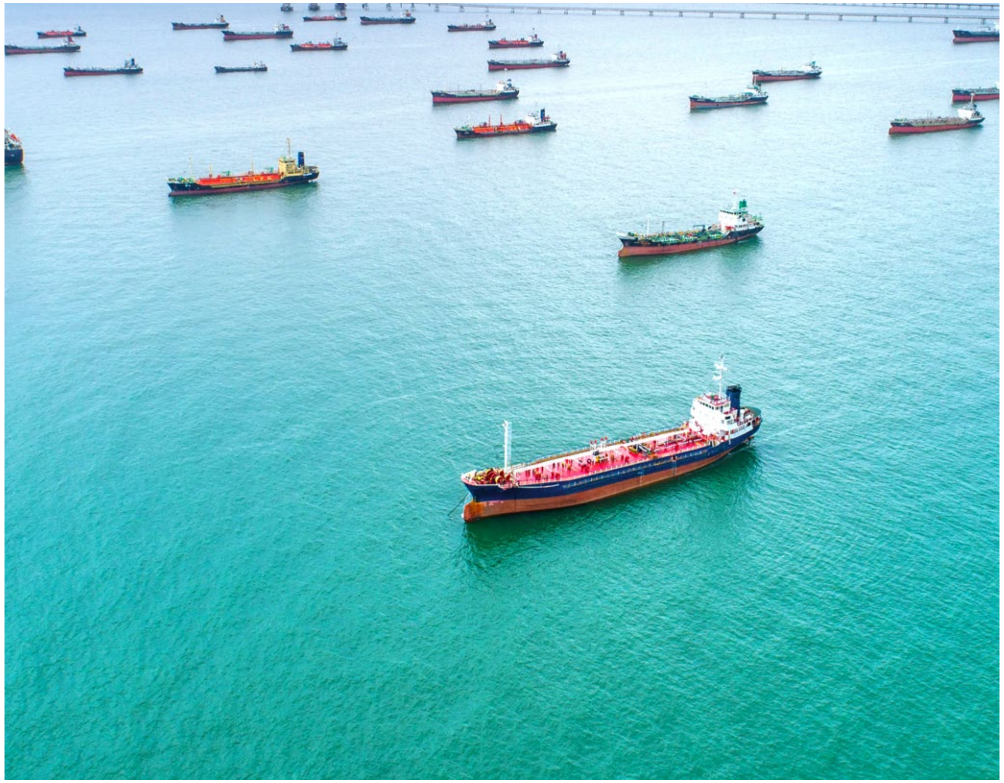
Article 40 I requires hydrogen network operators to cooperate at the EU level within the framework of the European Network of Hydrogen Network Operators in order to promote the functioning and development of the internal hydrogen market and cross-border trade. This is to ensure optimal management, coordinated operation, and proper technical development of the European hydrogen network.

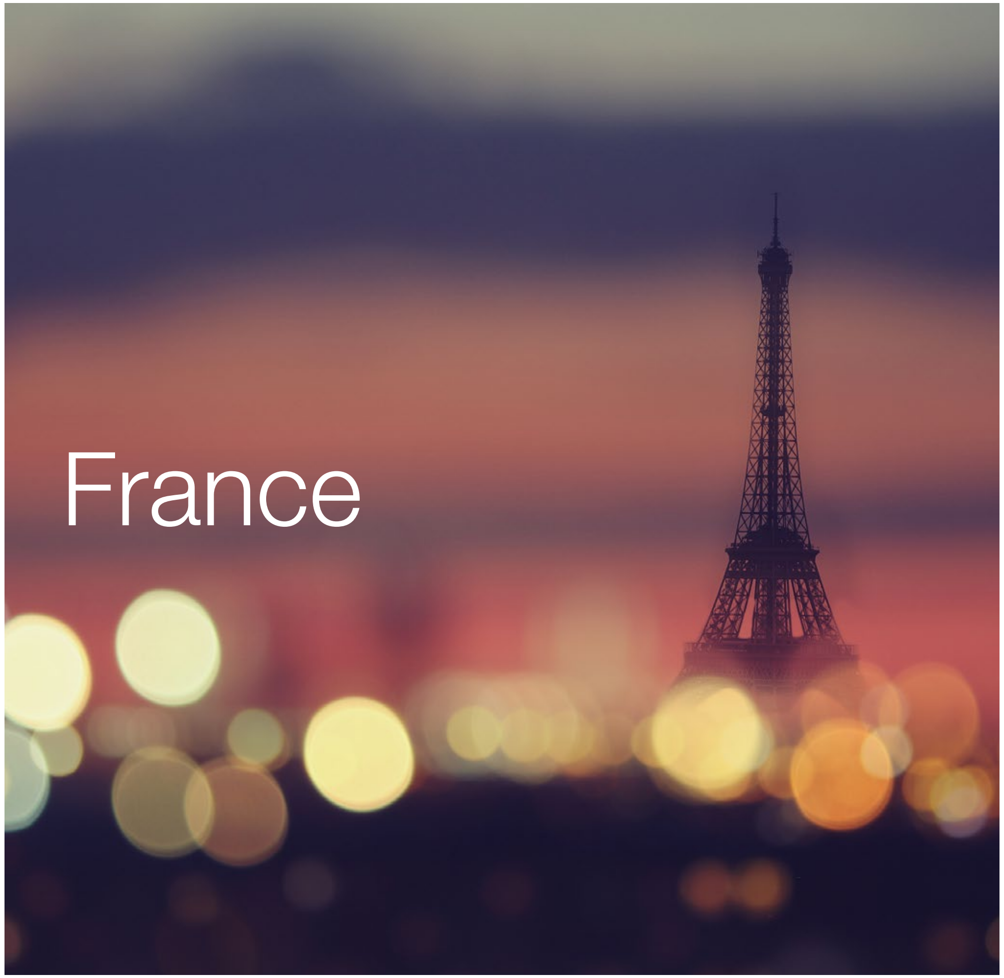
The annex to the Natural Gas Regulation also contains significant proposals for supplementing the Security of Gas Supply Regulation (EU SOS GasVO), which are of particular importance given the current turbulence in prices and low storage levels. This implementation of the third energy package for gas markets is a further concretization of the European Green Deal.

Effective dates

The Commission's drafts will be discussed in the European Parliament and the Council this year. Adoption is not expected before the end of 2022, and more than likely not until 2023.

While the ErdgasZVO and the EU SOS GasVO will have immediate legal effect upon adoption and publication, the GasRL, as a directive, must then be transposed into national law.





France

Regulators define three types of hydrogen by production type

Under article L. 811-1 of the French Energy Code, Hydrogen is defined as a gas containing various concentrations of dihydrogen molecules obtained after application of an industrial process.

According to article L. 811-1, three types of hydrogen are defined:

- **Renewable hydrogen**, which is produced either by electrolysis using electricity from renewable energy sources, or by means of any other technology that uses exclusively one or more of these same renewable energy sources and does not conflict with other uses allowing their direct recovery. In all cases, its production process emits, per kilogram of hydrogen produced, a quantity of carbon dioxide equal to no more than a given threshold.
- **Low-carbon hydrogen**, where the production process generates no more emissions than the threshold set for renewable hydrogen, but the hydrogen does not meet the other criteria necessary to be designated as renewable hydrogen.
- **Carbonaceous hydrogen**, which is neither low-carbon, nor renewable.

The threshold and proportions necessary to classify hydrogen according to the above definitions have not yet been established.

Pursuant to article L. 821-2, the renewable or low-carbon characteristics of hydrogen can be proven by traceability warranties based on a model similar to the one used to guarantee origin for renewable electricity.

Public support

In accordance with article L. 812-1 et seq., a system of grants was introduced in the Energy Code to support hydrogen production.

Production

Hydrogen production is subject to the "classified facilities for protection of the environment" regulation (*installations classées pour la protection de l'environnement* – ICPE), which imposes specific requirements and enhanced state scrutiny on facilities and activities that may harm the environment. The facilities and activities in scope are divided into sections.

Under section 3420 of the ICPE, the production of inorganic chemicals such as hydrogen in industrial quantities by chemical or biological transformation is subject to state authorization regardless of the quantities produced.

This authorization covers: (i) programs to mitigate risks to the environment; (ii) programs to prevent pollution of, and protect, water; and (iii) limits on greenhouse gas emissions.

Storage

Hydrogen storage is regulated. The relevant rules depend on the quantities of hydrogen being stored.

Under section 4715 of the ICPE, storage is subject to:

- State authorization when the quantity of hydrogen likely to be present in the facility is equal to or greater than 1 tonne.
- Notification to the regulatory authorities when the quantity of hydrogen is greater than or equal to 100 kg, but less than 1 tonne.

Under these thresholds, no permit is required.

The Mining Code covers the possibility of storing hydrogen underground.

Underground hydrogen storage is regulated by concession contracts. In principle, any concession must be subject to a public inquiry and open to competing bids. The concession contract determines the scope of the underground facility and the geological formations concerned. The duration of the concession is also determined by the contract and cannot exceed 50 years.

Transportation

Transportation is subject to different regulatory frameworks depending on whether hydrogen is transported via the pipelines of a dedicated transportation network or through the existing natural gas transportation network:

- If the pipeline is part of a transportation network dedicated solely to hydrogen, the regulatory framework has yet to be defined by the government.
- If the pipeline is part of the existing natural gas transportation network (this applies only to renewable hydrogen), the hydrogen is subject to the same regulatory framework as natural gas, namely:
    - The right of access to natural gas transportation facilities must be guaranteed by operators under the terms of the contract.
    - Charges for using transportation networks must be determined in a transparent and non-discriminatory manner.

Distribution

Distribution will be subject to different regulatory frameworks depending on whether hydrogen is distributed by pipelines that are part of a dedicated distribution network or the existing natural gas distribution network:

- If the pipeline is part of a distribution network dedicated solely to hydrogen (unlike the regulatory framework for transportation, this applies only to renewable energy), the regulatory framework has yet to be defined by the government.
- If the pipeline is part of the natural gas distribution network (this applies only to renewable hydrogen), the hydrogen is subject to the same regulatory framework as the distribution of natural gas:
    - A right of access to natural gas distribution facilities must be guaranteed by operators under the terms of the contract.
    - Charges for using natural gas distribution networks must be determined in a transparent and non-discriminatory manner.
    - In municipalities that are already served by a natural gas network, state owned gas distribution system operators are required to connect customers who so request to the existing state owned distribution networks.

Sales

The production of renewable hydrogen and its sale to end users take place in competitive markets that are not regulated by the Energy Code.

The sale of renewable gas injected into the natural gas network is not subject to supply authorization, provided that this gas is sold by the producer to a natural gas supplier.

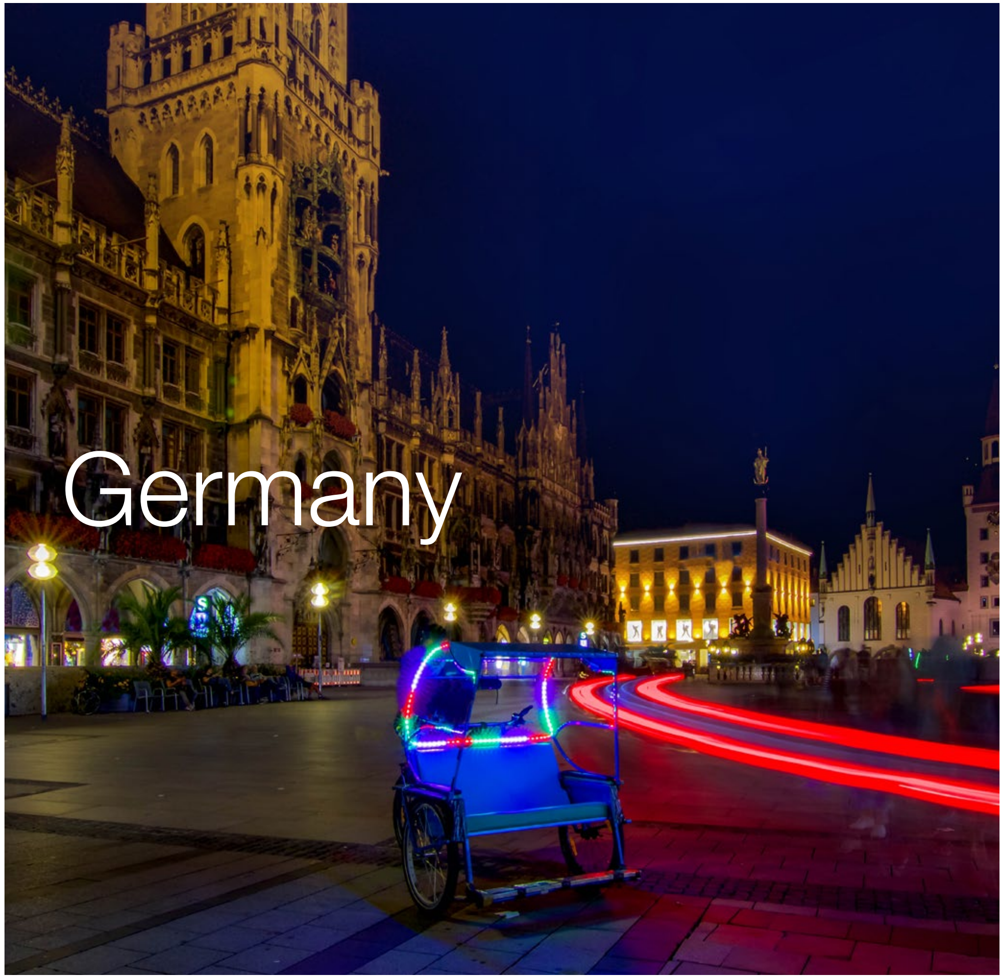
Pending legislation

On September 8, 2020, the French government announced a National Strategy for the Development of Decarbonized Hydrogen, which will provide €7 billion in public support by 2030, including €2 billion by 2022 under France's Recovery and Investments for the Future (*"France Relance et du Programme d'Investissements d'avenir"*) plans.

Following the adoption of Law No. 2019-1147 of November 8, 2019 on energy and climate, article L. 100-4 of the Energy Code on national energy policy was amended to include the objective of "developing low-carbon and renewable hydrogen and its industrial, energy and mobility uses." The Law also empowers the government to take any measure by ordinance that would "define a support and traceability framework for renewable and low-carbon hydrogen." This is the purpose of Ordinance No. 2021-167 of February 17, 2021 on hydrogen.

The Ordinance creates a new Book VIII in the Energy Code and defines three types of hydrogen according to their production methods. It also sets up a public support mechanism for hydrogen production and creates a mechanism for guarantees of origin and traceability to certify the type of hydrogen produced. Finally, a new regime for self-consumption of hydrogen has been introduced.

The Ordinance will be supplemented by three decrees and two application orders, which have yet to be enacted.



Germany

Hydrogen and natural gas networks will be subject to separate rules

Until now, only a few pipelines have been used exclusively for hydrogen. The pipelines used so far for hydrogen are mainly used for industrial purposes. These pipelines are classified as so-called "closed distribution networks" under Section 110 of the Energy Industry Act (EnWG). Therefore these pipelines are subject to only partial regulation and are exempt from incentive regulation in particular due to their use for industrial purposes. In fact, there has so far been no independent regulation of the hydrogen market in Germany. However, with the amendments to the Energy Industry Act of July 26, 2021, (*Energiewirtschaftsgesetz* – EnWG), new regulations on the use of hydrogen networks have come into force.

Pending legislation

According to the legal explanatory memorandum, the purpose of the amendments to the EnWG is the gradual development of hydrogen infrastructure in Germany. The regulations are intended as a transitional solution until European requirements are in place.

In the memorandum, the Federal Ministry of Economics (BMWi) also presented key considerations for the transitional regulation of hydrogen networks. According to these, the definition of gas should not be extended to hydrogen; instead hydrogen should be regulated separately, independently of the previous regulations regarding gas, under the EnWG.

The German government has stated that separate regulation of hydrogen and natural gas networks is imperative under the current EU legal framework. The EU Commission submitted proposals on this subject at the end of 2021 (see below). Transposition into German law is expected from 2025 onwards.

In light of evolving EU law, section 112b EnWG seeks to adapt the regulatory framework for the joint regulation and financing of gas and hydrogen networks.

The amendments to the EnWG add new or revise existing definitions under section 3, and include new provisions on the regulation of hydrogen networks under sections 28j-q, and on transitional regulation under sections 133a-c EnWG.

Separate definition of "hydrogen"

In the definition of "energy" in section 3 No. 14 EnWG, the words "and gas" are replaced by the words "gas and hydrogen." This basically places hydrogen alongside gas as a separate energy carrier. However, this should only apply to pure hydrogen pipelines. For the process of blending hydrogen into the natural gas grid, the existing legal framework remains in place. This is also illustrated by the unchanged wording of section 3 No. 19a EnWG, pursuant to which hydrogen produced by water electrolysis also falls under the gas definition.

Under the new definition, hydrogen is only considered "energy" within the meaning of the EnWG if it is used for grid-based energy supply, but not if used for non-performance-related supply.

Separate definition of "hydrogen network"

"Hydrogen network" is now defined independently in the EnWG and classified as a general supply network. Therefore, industrial pipelines that connect a generation plant only with specific consumption points and therefore are not general supply pipelines, are not covered by the EnWG under the term "hydrogen network."

Definitions of "gas" and "biogas"

The existing definitions of "gas" and "biogas" will be amended to distinguish clearly between the two substances. As a result, the existing definition of "gas" in the EnWG will be cleansed of its "hydrogen components."

Distinction between "hydrogen network operators" and "hydrogen plant operators"

A distinction is made between "hydrogen network operators" and "hydrogen plant operators" on the basis of the new unbundling rules. Pursuant to section 28m EnWG, operators of hydrogen networks are not allowed to build, operate or own facilities for the production, storage, and distribution of hydrogen. The intention of this provision is to prevent cross-subsidization and discrimination.

Opt-in clause until the new provisions under the EnWG come into effect

In the transitional phase, until new regulations have to be implemented in the EnWG as a result of new EU provisions, hydrogen pipeline operators are free to decide whether they wish to be subject to the hydrogen network regulation under the EnWG (via an opt-in clause). Operators of hydrogen storage facilities are therefore able to declare that access to their facilities should be in accordance with the regulations of the EnWG. Submission can be made by issuing an "opt-in declaration." If the pipeline operators, however, refuse to be subject to the EnWG, the few existing industrial hydrogen networks are not subject to the EnWG network regulation, until new EnWG regulations come into force.

If operators choose to opt-in under the regulations of the EnWG in the transitional phase, the regulations of the EnWG apply holistically, and not only to individual pipeline sections but to all the operators sections. Those who choose not to be regulated are not covered by the requirements regarding network access, tariff setting and unbundling. However, it is expected that this decision will only be of a temporary nature, because the German legislature (*Deutscher Bundestag*) anticipates that, in the medium term, it will be necessary to introduce comprehensive and mandatory regulations, without an opt-in clause, that apply for all hydrogen networks.

Infrastructure

Section 113a of the EnWG governs the transfer and continued validity of rights of way and land easements for gas pipelines. The provisions also apply to the operation of these pipelines if transporting hydrogen. This is intended to facilitate the conversion of gas pipelines into hydrogen pipelines.

Under section 113b EnWG, transmission system operators can identify pipelines that could be converted into hydrogen pipelines as part of the gas network development plan. They must ensure that the remaining network can meet capacity requirements.

Finance

As mentioned, the definition of "gas" in the EnWG will not be extended to hydrogen. Hydrogen will be regulated separately in the EnWG. This also means that there is no provision for interlinked financing via natural gas network fees.

On the question of financing, the BMWi holds the opinion that joint financing via joint network tariffs, to be paid by natural gas and hydrogen customers, is not permissible under EU law. According to the BMWi, financing should therefore be provided solely by hydrogen grid users, although public funding is likely to be required to avoid prohibitively high grid-usage tariffs from preventing the market from ramping up.

Section 28o of the EnWG provides for a cost-based tariff largely in line with section 21 of the EnWG.

The terms and conditions, and tariffs must be reasonable, non-discriminatory, and transparent, and must not be less favorable than those applied by network operators in comparable cases for services within their company or to affiliated or associated companies.

Operators of hydrogen networks have the option of receiving a monetary subsidy if they submit to an assessment by the German Federal Network Agency (BNetzA) of the adequacy of the respective hydrogen network infrastructure in terms of secure and economical supply. The prerequisites for such an assessment of the need for individual hydrogen network infrastructures are regulated under section 28p of the EnWG. If the assessment is successful in respect of the operator´s hydrogen network, the Federal Network Agency (BNetzA) approves the costs determined. However, the charges are not approved in accordance with section 23a of the EnWG.

Finally there is a provision in the EnWG, authorizing ordinances to establish the terms and conditions for the determination of costs.

United Kingdom

A patchwork of rules and policies, most from before hydrogen was viable

The UK lacks a comprehensive regulatory framework for the production, transportation, and storage of hydrogen. Stakeholders face a patchwork of rules and policies, most enacted before hydrogen was considered a viable alternative fuel.

Licenses

Hydrogen is covered by the definition of "gas" under the Gas Act 1986. A license under the Gas Act is required to ship, transport or supply hydrogen. No license is needed purely to produce gas, but production must be "unbundled" from transportation and supply.

The licensing requirements for parties that trade gas depend on whether they are physical or non-physical traders. In 2012, the UK Office of Gas and Electricity Markets (Ofgem) removed the requirement for "gas traders" (i.e., parties that are purely engaging in trading activities but are not involved in the physical conveyance of gas from one point to another) to hold a gas shipper license. However, parties that intend to physically ship gas will be required to hold a gas shipper license.

Production

Hydrogen production is subject to detailed health and safety rules, including:

- The Dangerous Substances and Explosives Atmospheres Regulations 2002, which requires employers to manage and control risks from the use or presence of dangerous substances in the workplace, which include flammable gases and liquids such as hydrogen.
- The Control of Major Accident Hazards Regulations 2015 (COMAH), which set out requirements in relation to the storage of dangerous substances (discussed in further detail below).

In addition, hydrogen production operations need to comply with environmental permit and planning conditions.

Storage

Hydrogen storage is regulated. The relevant rules depend on the quantities of hydrogen being stored.

A consent is required under the Planning (Hazardous Substances) Regulations 2015 (SI 2015/627) to store two or more tonnes of hydrogen.

Hydrogen is listed as a "dangerous substance" under the COMAH regime, and operators of an establishment where over 5 tonnes of hydrogen are present on site are under a duty to implement safety plans, emergency plans, and a "major accident prevention policy."

Sites covered by the COMAH regime are further divided into "lower tier" and "upper tier" establishments. "Lower tier" duties will apply where between 5 and 50 tonnes of hydrogen are present at the site. "Upper tier" duties will apply if the amount of hydrogen present at the site equals or exceeds 50 tonnes. If other hazardous substances are present onsite, there are additional rules under COMAH regarding how operators calculate the overall trigger thresholds for lower and upper tier status.

Operators of lower tier sites in the UK must notify the Competent Authority, prepare a major accident prevention policy, take "all measures necessary" to prevent a major accident, and report major accidents. Operators of upper tier sites, in addition to the duties placed on lower tier sites, must prepare a safety report and make arrangements for emergency planning.

The Competent Authority comprises the Health and Safety Executive (HSE), or the Office for Nuclear Regulation (ONR) for nuclear entities, acting together with the relevant environmental agency.

In England, the appropriate environmental agency is the Environment Agency (EA). In Wales, it is Natural Resources Wales (NRW), whereas, in Scotland, it is the Scottish Environment Protection Agency (SEPA). In Northern Ireland, COMAH is enforced by the Competent Authority that comprises jointly the Health and Safety Executive Northern Ireland (HSENI) and the Northern Ireland Environment Agency (NIEA).

As the COMAH regime applies to establishments where sufficient quantities of dangerous substances are potentially present, it may apply to hydrogen production and dispensing sites as well.

Transportation

By pipeline

A party will require a gas transporter license to transport hydrogen by pipeline. It must also adhere to the Pipeline Safety Regulations 1996, which set out requirements for the design, construction, installation, operation, maintenance, and decommissioning of pipelines.

At present, a dedicated hydrogen pipeline does not exist, so it may be necessary to transport hydrogen through the existing natural gas pipeline network by means of blending, followed by offtake. The concentration of hydrogen in gas pipelines is currently limited to 0.1 percent under the Gas Safety (Management) Regulations 1996 (GSMR). However, a blend of up to 20 percent hydrogen is currently being tested in the UK's HyDeploy project, and, if successful, may result in the GSMR being amended to allow up to 20 percent blending.

A gas shipper license is required in order to convey gas over a transporter's pipeline. Both gas shippers and gas transporters will also need to comply with industry codes, such as the Uniform Network Code, Retail Energy Code, and Smart Energy Code, as a condition of their license with Ofgem.

By road

The Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2009 place duties on parties with a role in the carriage of dangerous goods (including hydrogen), which cover, inter alia, the classification, packing, carriage, loading, unloading and handling of goods, as well as construction and the approval of vehicles.

Hydrogen can be transported by road in cryogenic liquid tanker trucks or gaseous tube trailers. The design and manufacture of equipment for transporting, storing, and regasifying hydrogen is regulated by the Pressure Equipment (Safety) Regulations 2016/1105.

Pending legislation

In its first-ever Hydrogen Strategy (August 2021), the UK government set out its use cases, and the steps for developing a full hydrogen value chain and achieving a hydrogen economy. The government also published its proposed business model to incentivize low carbon hydrogen production, and is consulting on the design of the Net Zero Hydrogen Fund and a new low carbon hydrogen standard.

The Hydrogen Strategy is, however, light in detail with regard to regulation, policy, and legal issues. The government has committed therein to:

- Review the suitability of the Gas Act for hydrogen, to ensure appropriate powers and responsibilities are in place to facilitate a decarbonized gas future.
- Review gas quality standards with a view to enabling the existing gas network to have access to a wider range of gases.
- Launch a "call for evidence," which will look at the current gas types and assess the potential role of hydrogen in the existing gas system.
- Set up a "hydrogen regulators forum" to assist with developing the area.

The government also is working with industry and regulators to consider the non-economic regulatory frameworks required to support the hydrogen value chain, and has formalized this engagement through the Hydrogen Regulators Forum.

The Secretary of State for Business, Energy and Industrial Strategy plans to publish initial conclusions, proposals, and next steps on regulation in a hydrogen strategy update in early 2022.

In addition, a new Hydrogen Policy Commission, comprising senior politicians, experts from the UK's private sector, and academics, was set up at the end of January 2022 to advise policymakers on the deployment of green and blue hydrogen across the UK economy. The Hydrogen Policy Commission will be conducting an assessment of the government's Hydrogen Strategy, and is expected to publish its findings later this year. Over the coming months, the Hydrogen Policy Commission will also be engaging with representatives from industry and academia, as well as senior officials from national and local government, to establish the steps needed to realize the opportunities presented by hydrogen.

China

A gradual awakening to hydrogen as a primary energy source

China recognizes hydrogen as an important form of secondary energy that is critical to reach carbon peaking and carbon neutrality based on the Hydrogen Industry Development Plan – Mid-to-Long Term (2021 to 2035) (Hydrogen Industry Plan), issued by the National Development and Reform Commission and the State Energy Administration on March 23, 2022. In the absence of a new nationwide regulatory framework, the production, transportation, storage, and usage of hydrogen are currently subject to the legal framework applicable to hazardous chemicals.

Production

Under the relevant laws and regulations on hazardous chemicals, the production of hydrogen in China requires two types of licenses:

- A safety production license for hazardous chemicals, obtained from the competent provincial-level production safety supervision and administration bureau
- A production license for industrial products, obtained from the competent provincial-level market supervision and administration bureau

Storage

The storage of hydrogen requires an operation license for hazardous chemicals, obtained from the competent county-level production safety supervision and administration bureau. Hazardous chemicals should be stored in specified warehouses and managed by specially assigned personnel. The storage of gaseous hydrogen should comply with detailed rules and specifications relating to hydrogen safety, hydrogen containers, and markings.

The pressure vessels (including cylinders) for hydrogen storage are considered special equipment and so regulated by the safety supervision authorities. Entities that engage in hydrogen storage should comply with work safety measures and engage a qualified institution to conduct periodic safety inspections and assessments to ensure safe working conditions.

Transportation

By pipeline

The planning, construction, and operation of pipelines for the transportation of hydrogen should comply with the Safety Management Regulations on the Pipeline Transportation of Hazardous Chemicals issued by the State Administration of Work Safety.

According to the China Hydrogen Energy and Fuel Cell Industry White Paper (2019) issued by the National Alliance of Hydrogen and Fuel Cells, as of 2019, there was only 100 km of pipeline dedicated to the transportation of hydrogen across the whole of China. Considering the huge costs of hydrogen pipeline construction, the suggested approach is to explore transportation via hydrogen-blended natural gas pipelines and making full use of the existing pipeline network in China.

By road

Under the Administrative Provisions on Road Transport of Dangerous Goods issued by the Ministry of Transport, any entity that engages in the transportation of dangerous goods should obtain a dangerous goods road transportation license and set up a sound safety management system that meets the relevant technical standards and requirements.

"Dangerous goods" are defined as those listed on the List of Dangerous Goods (GB 12268 -2). Frozen liquid hydrogen (No. 1966) and compressed hydrogen (No. 1049) are both on the list.

Use

Under the Hazardous Chemicals Safety Regulations, if a chemical company intends to use more than 160 tonnes of hydrogen a year, the company must obtain a usage safety license for hazardous chemicals from the competent local safety supervision and administration bureau.

Pending legislation

The National Energy Administration issued a draft consultation on the Energy Law of the People's Republic of China in April 2020 (Draft Energy Law) in order to promote the development of energy technology and improve energy efficiency.

A key development under the Draft Energy Law is that hydrogen is listed as a type of "energy" for the first time in government legislation, together with coal, oil, gas, and other types of renewable energy. This is regarded as a critical step for the development of the hydrogen industry in China as the draft legislation, once promulgated by the National People's Congress, will recognize hydrogen as a type of energy, instead of a hazardous chemical as is the case under the current regulatory framework.

Key policies and guidance

In February 2021, the State Council issued the Guiding Opinions on Accelerating the Establishment and Improvement of Green and Low-Carbon Circular Development Economic System, which set out sustainable development objectives, such as increasing the share of energy consumption from renewable sources, vigorously promoting the development of renewable energies including hydrogen, and strengthening the construction of infrastructure for electric vehicle charging and hydrogen refuelling.

In March 2021, the National People's Congress approved the Outline of the 14th Five-Year Plan for National Economic and Social Development, and the Long-Range Objectives through the Year 2035 for the PRC, which stated that China is to deploy a number of future industries in the fields of cutting-edge technology and industrial transformation. Hydrogen energy and storage are both given as future industries that require forward-looking planning.

The Hydrogen Industry Plan sets out some ambitious targets for the development of hydrogen in China, including achieving annual production of 100,000 to 200,000 tonnes of hydrogen by 2025 through the use of renewable energy.

Singapore

Updated fuel safety rules in 2020; plans to decarbonize maritime industries

Singapore has no hydrogen-specific legislation in place at this time. The import, storage, sale, and transportation of hydrogen are governed by broader legislation covering flammable materials generally and workplace health and safety laws.

Licenses

Hydrogen is a "flammable material" under the Fourth Schedule to the Fire Safety (Petroleum and Flammable Materials) Regulations 2020 (P&FM regulations). As such:

- A P&FM storage license is required to store any quantity of hydrogen.
- A P&FM transportation license is needed to transport (by road) more than 130 kg (gross weight) of hydrogen gas in not more than two cylinders or more than 20 liters of liquefied hydrogen. This license is specific to each vehicle used in such transportation; that means transporters will need as many licenses as they have vehicles.
- A P&FM import license is needed to import more than 130 kg (gross weight) of hydrogen gas in not more than two cylinders or more than 20 litres of liquefied hydrogen. The importer must have at least one P&FM storage license to apply for a P&FM import license.
- A P&FM pipeline license is needed to transport any amount of hydrogen through a pipeline. Pipeline owners are responsible for obtaining this license.

The Singapore Civil Defence Force (SCDF) issues each license above.

Production and storage

Hydrogen production and storage are subject to detailed health and safety requirements, including:

- The Workplace Safety and Health Act 2006, which requires hydrogen manufacturers and suppliers to register factories and ensure information on precautions, health hazards, and test results is available to everyone who uses hydrogen at work.
- The Workplace Safety and Health (Major Hazard Installations) Regulations 2017, which require occupiers of facilities where hydrogen is processed, manufactured, or stored in bulk to register the facilities, prepare and maintain a safety case, notify and report incidents, and share information with regulators from time to time.
- The Fire Safety Act (FSA), under which storage facilities must comply with fire safety requirements for the storage of flammable materials in premises. All storage must also be indicated in building plans submitted to the SCDF for approval. There is no quantity-based exemption for this obligation.
- The Fire Safety (Building and Pipeline Fire Safety) Regulations and an accepted code of practice, which require that the storage licensee for any licensed premises must ensure that the premises' ventilation, fire escapes, structural fire precautions, and fire prevention and extinguishing systems.

In addition, hydrogen production operations will need to comply with the usual environmental permit and planning conditions.

Transportation

By pipeline

As noted above, pipeline owners must have a license to transport hydrogen by their pipelines. Under the P&FM regulations, they must also conduct safety checks and regular maintenance, adopt an accepted code of practice, and have a compliant in-house company emergency response team of six people (larger teams are advisable, though not required, for larger premises), unless otherwise directed. In addition, pipeline users must help the licensee carry out its duties, including by preventing leaks or spills from sections of pipeline under the user's control.

By road

In addition to the licensing requirements set out above, hydrogen must be transported only during pre-approved hours and on pre-approved routes; under the FSA and the Environmental Pollution Control Act, drivers transporting hydrogen by road must hold a driver permit for hazardous materials transportation; and transportation vehicles must satisfy the inspection checklist set out by the SCDF.

Collection points

Importers (or their authorized agents) must take delivery of hydrogen at: (i) a wharf, if imported by water; (ii) an air cargo terminal, if imported by air; or (iii) the Tuas Checkpoint, if imported by road. Import by rail is not allowed.

Sale and purchase

Any storage licensee operating a dispensing station or pump must comply with the detailed safety measures set out in the P&FM regulations and must not sell or supply hydrogen to anyone unless the licensee is satisfied that the recipient holds a license to store or transport hydrogen. Additionally, all sales must be recorded and records maintained.

Spot and derivative trading

Carrying on spot trading of hydrogen is licensable under the Commodity Trading Act 1992 unless an exemption applies, while dealing in derivatives contracts of which hydrogen is the underlying is licensable under the Securities and Futures Act 2001 unless an exemption applies. Depending on the type of trading activity, exemptions are available for own-account dealing activities and dealing with regulated entities such as banks.

No pending legislation is being considered at this time. That said, the government is studying the feasibility of producing hydrogen in Singapore and the role hydrogen could play in decarbonizing the maritime industry in Singapore. (A prior study was undertaken in 2021 and concluded that green hydrogen cannot be produced in Singapore due to land constraints.) In addition, a group of four companies are jointly studying the technical and commercial viability of a liquefied hydrogen supply chain in Singapore.

UAE

Petroleum, energy and environmental authorities have sway over hydrogen

At present, the UAE lacks a specific regulatory framework for the licensing and implementation of hydrogen transportation, storage, transmission and distribution networks. The limited regulation of hydrogen in this region is discussed below.

Licenses

In Abu Dhabi, the Supreme Petroleum Council (SPC) creates and oversees the implementation of general and fiscal policy in relation to gas resources.

In Dubai, the Dubai Supreme Council of Energy is responsible for policy development with a view to developing new energy sources.

In Sharjah, the Petroleum Council of Sharjah is responsible for regulating the gas industry and granting concessions.

These departments also oversee licensing activities in the energy sector, proposing fees, tariffs, and prices.

Production, storage and transportation

Under UAE law, any entity wishing to participate in the import, distribution, transport, sale or storage of petroleum products, including gas, must first obtain a trading authorization from the SPC, and also a license from the Department of Energy. A license is also required from the Federal Environment Agency before commencing any gas-related project.

Abu Dhabi National Oil Company (ADNOC) has the right to exploit and use all such gas, either alone or in partnership with others, so long as ADNOC's ownership of any project is at least 51 percent.

Upstream concession rights in relation to gas in Abu Dhabi are limited to the right to extract gas in return for a handling and delivery fee: only ADNOC is permitted to sell gas extracted in Abu Dhabi. ADNOC has a number of subsidiaries involved in exploration and production, processing and refining, and marketing and distribution.

Abu Dhabi imports gas to the Taweelah receiving facilities from Qatar using the Dolphin gas pipeline. Dolphin Energy operates this facility. ADNOC Gas Processing operates the Taweelah-Maqta pipeline.

United States

Legislation would promote hydrogen vehicles but no plans to regulate hydrogen wholesale

At present, the United States lacks comprehensive federal regulation governing the use of hydrogen. Several federal agencies possess authority – by virtue of their regulatory jurisdiction over conventional energy sources such as oil and natural gas – to regulate hydrogen at different stages in the production. Currently, the main regulators are:

- The Department of Energy (DOE)
- The Federal Energy Regulatory Commission (FERC)
- The Pipeline and Hazardous Materials Safety Administration (PHMSA)
- The Environmental Protection Agency (EPA)
- The Occupational Health and Safety Administration (OSHA)

Licenses

The United States has no federal licensing scheme governing the production, transportation, or sale of hydrogen, and such requirements typically are set at the state level.

Production

The EPA – by virtue of its broad mandate to regulate substances that have an impact on human health and the environment – currently possesses indirect regulatory authority over hydrogen production. For example, hydrogen production is tangentially regulated under the EPA's (i) Mandatory Greenhouse Gas Reporting Program; (ii) effluent standards under the Clean Water Act; and (iii) Chemical Accident Prevention Program. However, under the reporting program and effluent standards, hydrogen is merely regulated as an offshoot of fossil fuel regulation rather than standing alone. Specifically, the regulatory scope is confined to hydrogen produced as a by-product of traditional fossil fuel production and processing, such as production via feedstock (methane steam reformation to produce "grey hydrogen") and as a refinery by-product. Accordingly, as production begins to shift away from traditional fossil fuels toward cleaner energy sources, such as wind and solar energy ("green hydrogen"), these sources of regulatory authority will no longer be appropriate, driving the need for updated, tailored federal regulatory power.

Transportation and distribution

At present, the transportation and distribution of hydrogen is primarily regulated by PHMSA. For example, under 49 CFR Part 192, PHMSA is tasked with imposing "minimum safety requirements for pipeline facilities and the transportation of gas." Additionally, 49 CFR section 173.301 – 302 governs the shipment of compressed gases, while section 173.230 regulates the design of fuel cell cartridges. As such, because hydrogen falls within the definitional scope of a "flammable gas," these standards apply. However, because these minimum standards only contemplate the small-scale usage of hydrogen or the regulation of compressed gases generally, PHMSA has been conducting research to inform the updating of these standards to enable the commercial-scale transportation of hydrogen. Thus, it is likely that as commercial-scale hydrogen transportation and deployment become more prevalent, PHMSA will update its standards and regulations to address the chemical/compositional risks associated with hydrogen transportation.

Storage

OSHA is the primary federal regulator regarding hydrogen storage. In particular, 29 CFR section 1910.103 of the OSHA regulations specifically deals with hydrogen storage, prescribing standards concerning, among other things, (i) location, (ii) testing, (iii) supervision, and (iv) ventilation. Additionally, other sections of the OSHA regulations not specifically intended to contemplate hydrogen may be used to regulate hydrogen, such as standards associated with liquefied and compressed gases.

Trading

There are currently no comprehensive regulations or rules governing the trading of hydrogen.

Pending legislation

There are currently no legislative proposals contemplating the wholesale regulation of hydrogen in the United States. However, there have been a flurry of bills introduced in Congress related to hydrogen. For example, a more narrowly focused bill sponsored by U.S. Senators Chris Coons (D-Del.) and John Cornyn (R-Texas), dubbed the Hydrogen for Trucks Act (S.3806), was recently introduced in the Senate, with companion legislation also introduced in the House of Representatives. In short, this bill would: (i) incentivize the adoption of heavy-duty hydrogen fuel cell vehicles by covering the cost difference between these vehicles and traditional diesel vehicles; (ii) encourage parallel deployment of vehicles and fueling stations; and (iii) use fleet performance data to incentivize private investment and accelerate hydrogen deployment. Similarly, Debbie Lesko (R-Ariz.) introduced a bill dubbed the Advancing Hydrogen Power Research and Development Act in February 2022. In essence, the bill would aim to facilitate the identification of barriers to hydrogen as a fuel source, paving the way for the future exploration and use of hydrogen.

Although it is not certain – nor likely – that these bills will pass, the confluence of legislative and executive interest in hydrogen continues to grow. For example, there has been keen interest by the Biden administration in the deployment of hydrogen as an effective means to reach broad decarbonization pronouncements. For example, in his first state of the union address, President Joe Biden made express his administration's interest in hydrogen as a means to meeting clean energy goals. As such, with interest in hydrogen permeating the highest levels of government, it is inevitable that comprehensive regulation is likely to follow in lockstep with increased adoption and deployment.

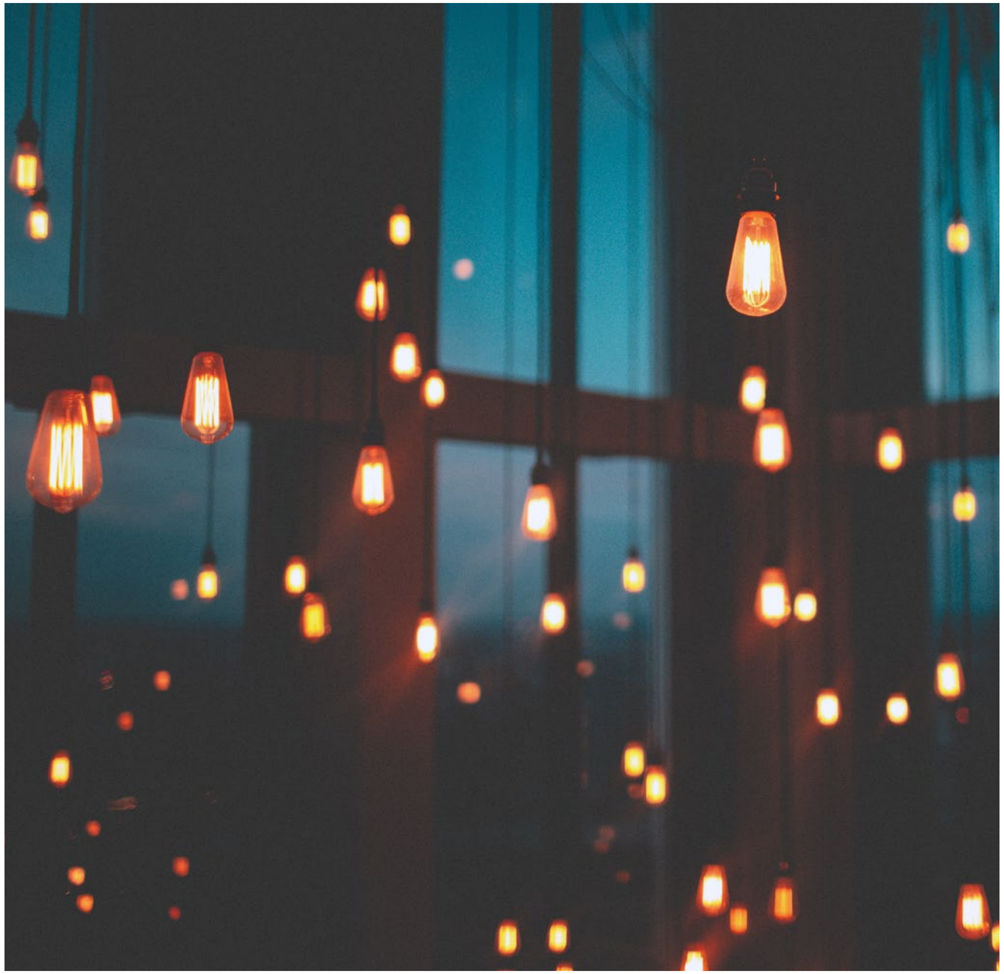
Bipartisan Infrastructure Law (BIL)

The BIL, signed by President Biden on November 15, 2021, authorizes about $9.5 billion for hydrogen-related matters. The BIL appropriates $8 billion for regional clean hydrogen hubs, $1 billion for a clean hydrogen electrolysis program and $500 million for the clean hydrogen manufacturing initiative and the clean hydrogen technology recycling RD&D program. With respect to regional clean hydrogen hubs, the BIL requires the DOE to "establish a program to support the development of at least four regional clean hydrogen hubs that:

1. demonstrably aid the achievement of the clean hydrogen production standard developed under the BIL,
2. demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen, and
3. can be developed into a national clean hydrogen network to facilitate a clean hydrogen economy."

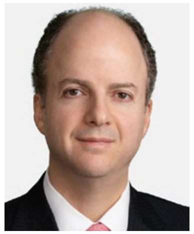
On February 15, 2022, the DOE issued a Request for Information (RFI) regarding regional clean hydrogen hubs, in order to assist in decarbonizing industry sectors, such as transportation, residential and commercial heating, power generation, and ammonia and steel. Under the BIL, one of the four hubs must address feedstock diversity and one must address end-use diversity. In addition, the hubs shall be located in different geographic regions of the United States, with at least two of the hubs located in regions with the greatest natural gas resources. Comments on the regional clean hydrogen hub RFI were due on March 21, 2022.

The DOE issued a second RFI regarding the clean hydrogen electrolysis program on February 15, 2022. The second RFI "focuses on hydrogen and related technologies, such as electrolyzers, fuel cells, and storage tanks" that "can play a key role in decarbonizing multiple [industry] sectors." Comments on this RFI were due on March 29, 2022.



Authors

Nicolas Borda (United States)



Nicolas is based in Reed Smith's Houston office and is an international business transaction lawyer with a focus on energy and natural resources, infrastructure, and Latin America. Nicolas focuses his energy practice on all facets of oil and gas (upstream, midstream, and downstream), power and renewable energy projects. He advises clients on international and cross-border transactions, regulatory matters, mergers and acquisitions, corporate, joint ventures, energy infrastructure project development, government procurement, public policy, anticorruption, compliance, HSE, NAFTA, USMCA, international trade, and dispute resolution in the energy sector. Nicolas has been involved in many energy projects and transactions throughout Latin America. Nicolas is ranked by Chambers Global and Chambers Latin America. Nicolas advises U.S. and international companies in all kinds of business and cross border transactions regarding natural resources.

Simone Goligorsky (United Kingdom)

Simone is a partner based in Reed Smith's London office. She advises banks, hedge funds, utilities and energy and commodity companies on a variety of transactional, trading, cross-border regulatory, compliance and risk management matters within the energy sector. Simone has extensive experience working on transactions involving the acquisition and disposal of energy and non-energy commodity portfolios, assets and businesses; along with more structured transactions, involving energy management and market optimization structures, as well as market access arrangements. She has documented, structured, analysed and negotiated both physical and financial UK and European energy commodity agreements for a range of clients. Simone is ranked as a Rising Star in the Legal 500 UK.

Simon Grieser (Germany)

Simon is a founding partner of the firm's Frankfurt office and a member of the Financial Industry Group of Reed Smith. His practice focuses on the advice of national and international financial institution in connection with banking & finance and banking regulatory issues as well as on securitization. He advises frequently investors and financiers on all aspects of regulatory topics to provide financial services and energy matters in Germany. He is a frequent speaker and author on banking & finance and regulatory topics. National and international publications recommend him regularly in the area of "Regulatory Banking Sector."

Colette D. Honorable (United States)

Colette leads the firm's Energy Regulatory group and is a member of the firm's executive committee. She is also a member of the firm's ESG group and is resident in the Washington, D.C., office. Colette is a highly regarded thought leader and strategist in domestic and international energy sectors. Colette recently served as Commissioner at the Federal Energy Regulatory Commission (FERC). She was nominated by President Barack Obama in August 2014, and unanimously confirmed by the U.S. Senate, serving from January 2015 until her term expired in June 2017. At the firm, Colette is a trusted advisor and counselor to several Fortune 500 energy companies, investor-owned utilities, renewable energy and technology companies. In this capacity, she provides strategic advice and counsel in a number of areas, including ratemaking matters, clean energy integration, performance-based ratemaking, achieving ESG goals and environmental justice issues. In her work, Colette supports clients working to mitigate the impacts of climate change, and also advises clients on the development and execution of inclusion strategies.

Eric Lin (China)

Eric has more than 22 years' experience in energy and natural resources projects, cross-border M&A and foreign direct investment in China. He has particular experience in advising on complex foreign investment transactions in China with some of them being the first of their kind or multibillion-dollar joint ventures. Eric has also developed a China outbound practice in advising Chinese clients for overseas investment. Eric has worked on transactions involving the industries of power (conventional, renewable and hydro), mining, petrochemicals and machinery production for the hydrogen supply chain.

Adela Mues (UAE)

Adela is a partner in our Global Corporate Group in Dubai. She has extensive experience working on broad transactional and regulatory matters across a variety of industries, focusing on venture capital, private equity, mergers and acquisitions, corporate reorganizations, joint ventures, fund formation, equity capital markets, commercial agreements, employment, and general corporate matters. Adela has worked extensively across the Middle East and the United Kingdom and has been based in the Middle East for over 13 years.

Debra A. Palmer (United States)

Debra is based in the Washington, D.C., office. Her practice focuses on energy regulatory matters, with an emphasis on matters involving the Federal Energy Regulatory Commission (FERC), state public utility commissions, and the federal courts. She has more 30 years of experience with federal regulatory issues facing the energy industry, and has assisted her clients in pursuing their goals before FERC, state regulatory agencies, and the federal appellate courts. Debra advises clients with varied interests in the energy & natural resources sector, including natural gas companies, local distribution companies, oil and gas pipeline companies, and electric utilities. Her ability to understand regulators' goals and present her clients' interests accordingly has helped her become a leading advocate for energy firms across the United States. Deb understands the interrelationship between operational, business, and regulatory concerns faced by the energy industry. She has cultivated a deep knowledge in these areas, earning a reputation as a trusted advisor in the planning, operating, financial, regulatory and reliability issues facing the rapidly changing natural gas and electric industries.

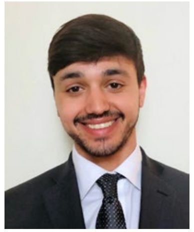
Hagen Rooke (Singapore)

Hagen is based in Reed Smith's Singapore office and has extensive experience advising on financial regulatory matters. His practice covers a broad range of areas, including financial services licensing and approvals, conduct of business and regulatory change projects. His clients include banks, payment services firms, digital asset exchanges and dealers, capital markets intermediaries, funds and fund managers, exchanges, proprietary trading houses and commodity groups. With extensive experience of engaging with the Monetary Authority of Singapore (MAS) and other regulators, and of practising in Asia and Europe, Hagen provides strategically valuable advice and has a unique understanding of the international issues and synergies that are relevant to clients. Clients have also commented that "His advice has always been practical, sharp, commercial and technically sound."

Nicolas Walker (France)

Nicolas is a partner in the firm's Paris office. He focuses on environmental law, urban planning and more generally in all aspects of administrative and real estate law. Bilingual French-English and dual-trained in Common and Civil law systems, Nicolas assists a range of international clients with large development projects, compliances issues and relationships with French government authorities. Nicolas appears regularly before the administrative courts in merits review cases. Nicolas also devotes a significant portion of his practice to corporate social responsibility and human rights matters, with a focus on environmental sustainability, green advertising, reforestation (public-private partnerships) and the right to water for vulnerable communities.

Karim Alhassan (United States)



Karim is based in the Washington, D.C., office and focuses his practice on assisting clients with their compliance obligations regarding data privacy and security. More specifically, he has experience advising clients on their regulatory obligations stemming from emerging state privacy laws, as well as assisting in the defense of companies subject to regulatory investigations and actions by the Federal Trade Commission. Additionally, Karim has experience navigating the emerging and rapidly changing regulatory landscape in connection with digital assets, assisting on matters related to cryptocurrency advertising and under the federal securities laws.

Albertine Aquenin (France)

Albertine is an associate in the Paris office in the Energy & Natural Resources Industry Group, specialised in public law, with experience in environmental law, urban planning energy law, public contracts and procurement, procedures with regulators and all forms of merits and judicial review of government action. Albertine assists international and domestic clients with their legal and regulatory compliance issues and relationships with French public institutions.

Nicole Cheung (United Kingdom)

Nicole is an associate based in Reed Smith's London office. She works with clients in the energy and commodities sectors on a variety of transactional, cross-border regulatory, compliance and risk management matters.

Tufayel Hussain (UAE)

Tufayel is an associate in the Global Corporate Group. He advises clients across a broad range of sectors on corporate and commercial matters, with particular experience in mergers and acquisitions, cross-border transactions and commercial advisory work. Tufayel's experience covers a wide range of industry sectors and has acted for various clients, including major listed corporations, growth companies and start ups. Tufayel qualified in London and is based in the firm's Dubai office. He has gained invaluable commercial exposure in the Middle East and has extensive experience in the laws of that region and working for companies and assisting with their general commercial needs.

Ievgeniia Burkhart (United Kingdom)

Eva is a paralegal in our Energy & Natural Resources Group and Reed Smith's Future Trainee Solicitor. Eva joined the firm as a Queen Mary placement student in 2021 and gained experience in contentious and non-contentious energy and commodity matters. Eva has assisted clients with complex commercial disputes before the English High Court, as well as acted in trade association arbitrations, including under the GAFTA and FOSFA rules. Eva's non-contentious experience has involved drafting a bespoke Reed Smith's precedent for an offtake of oil products.

Zahir Sabur (UAE)

Zahir is a senior associate in our Global Corporate Group in Dubai with over 10 years' experience advising on a broad range of transactions across the world, including the United Kingdom, North and South America, the Middle East and Africa. Zahir's practice focusses on international M&A and private equity transactions, direct and indirect investment, venture capital and joint ventures. He also counsels clients on corporate governance and ethics and compliance matters involving government entities and multinational corporations.Zahir has depth of experience across a broad range of sectors, including oil & gas (both exploration and downstream), renewables, commodity trading, real estate, agriculture, health care, banking, hospitality and life sciences.

Green hydrogen in Latin America: A new era has started

By Nicolas Borda and Karim Alhassan

Takeaways

- Hydrogen use does not emit CO_2, but most methods of producing it do
- Latin American countries are making a concerted effort to produce green hydrogen
- Natural gas supply is becoming precarious, which may increase reliance on hydrogen

Today, no international market exists for pure green hydrogen. However, Latin America may play a prominent role in developing such a green market. Latin America is one of the geographic regions with the most renewable energy potential to help produce green hydrogen and achieve a future with net-zero emissions. The International Energy Agency (IEA) recently produced a report on the potential of low-carbon hydrogen in Latin America, stating that Argentina, Brazil, Chile, Colombia, Costa Rica, El Salvador, Panama, Paraguay, Trinidad and Tobago, and Uruguay are preparing national hydrogen strategies. The report also provided a list of low-carbon projects in development in the region.

Hydrogen has become a familiar term. It is the most common element in the world, and it has tremendous potential as a clean energy source. Hydrogen even makes up around 10 percent of the human body by mass. It is always adhered to other molecules, like oxygen (as it is in water).

Hydrogen does not emit carbon dioxide when used by the end user; however, the production process, with the exception of green hydrogen and pink hydrogen, does produce CO_2.

All countries in Latin America will need to decarbonize their transportation to be able to meet their clean energy objectives. Since 2008, there have been several low-carbon pilot projects in Argentina, Chile, and Costa Rica. In Chile, using green hydrogen rather than diesel for copper production will also have a very positive impact in terms of greenhouse gas reduction.

Types of hydrogen

1. Green hydrogen is produced using mainly solar and wind energy, resulting in no greenhouse gas emissions.
2. Blue hydrogen is produced using natural gas and steam.
3. Black and brown hydrogen are produced using coal.
4. Yellow hydrogen is produced exclusively using solar energy.
5. Turquoise hydrogen is produced using methane pyrolysis.
6. White hydrogen occurs naturally in underground deposits (there are currently no strategies to exploit this type hydrogen).
7. Pink hydrogen is produced using nuclear energy.

These color codes are used by the energy industry to differentiate between the types of hydrogen produced.

Uses

The main uses for hydrogen include:

- **Industrial processes** – Refining oil (upgrading heavy oil and desulphurization), producing fertilizer (25 percent of ammonia was used to produce urea), treating metals, and processing foods.
- **Space exploration** – NASA began using liquid hydrogen as rocket fuel 70 years ago.
- **Transportation** – Hydrogen is considered an alternative fuel under the Energy Policy Act of 1992. There is an increasing desire to use hydrogen in aircraft, trucks, cars, and vessels primarily to power fuel cells. Japan and California are leaders in hydrogen charging stations.
- **Electricity generation** – Hydrogen is used as fuel in power plants. Some natural gas turbines also use a hydrogen/gas mix.

Countries in Latin America have different levels of industrialization. Argentina, Brazil, Chile, Colombia, and Mexico are the largest economies in the region, and these five countries, together with Trinidad and Tobago, account for almost 90 percent of the demand for hydrogen in the region. Trinidad and Tobago alone accounts for around 40 percent of the demand in Latin America for use in its huge chemical industry that produces large volumes of ammonia, methanol, and urea produced for export.

In Mexico, oil refining consumes 60 percent of the local demand, followed by steel production where hydrogen-rich synthetic gas is used for direct iron reduction (DRI). In Brazil, oil refining accounts for around 80 percent of the demand, followed by ammonia-based fertilizer production. In Argentina, hydrogen is in demand for three industrial uses (oil refining, ammonia and methanol production, and DRI). Chile and Colombia account for about 10 percent of the total hydrogen demand for the region.

Latin American and Caribbean countries form a new platform

November 30, 2021, marked the official launch of H2LAC, a collaborative platform that seeks to promote the development of green hydrogen in Latin America and the Caribbean, bringing together representatives from more than 19 countries.

The H2LAC initiative is endorsed by the German Society for International Cooperation (GIZ), the Economic Commission for Latin America and the Caribbean, the EUROCLIMA+ Program, the World Bank, and the Hydrogen Alliance.

At the launch, Gonzalo Muñoz, high-level climate action champion of COP25, highlighted "the importance of the sector for increasing the ambition of reaching a maximum of 1.5º Celsius temperature increase set by the Paris Agreement and the important opportunity that the development of H2V represents for the region to 'sow a seed' for the rest of the world; opening opportunities for collaboration not only North-South but also South-South."

Max Correa, director for fuels and new energies at the Chilean Ministry of Energy, stressed that *"the H2V strategy generated by the Chilean Government will be implemented as a state policy, through serious and rigorous work, covering all possible areas so that this industry can be born."*

Chile aims to become a leading hydrogen exporter and operate as a hub to establish a green fuel supply chain for the world, alongside other countries in Latin America and the Caribbean.

Rainer Schröer, director for renewable energy and energy efficiency at GIZ Chile, pointed out that *"[T]he objective of the platform is to host a repository of green hydrogen projects at regional level in Latin America and the Caribbean in order to position the discussion at global level, since, so far, the discussion has been very focused on Europe."*

Each of the participants involved in the H2LAC initiative will perform different roles in the development of the platform based on their institutional nature.

Costs of green hydrogen

The costs associated with renewable energies continue to decrease, especially in large-scale wind and solar projects. Therefore, the costs associated with green hydrogen is also expected to decrease in the near future.

Current geopolitical events and climate change

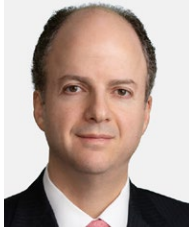
Countries in Europe and Latin America want greater energy independence. Mexico imports a significant amount of natural gas from the United States. The freezing temperatures in Texas in February 2021 significantly impacted the flow of natural gas to Mexico, and prices in the spot market became incredibly expensive. Europe is trying to reduce its dependency on natural gas from Russia in response to the current crisis in Ukraine.

Conclusions

Reliability of supply (including price), the fight against climate change, and the need for energy security will all bolster the use of alternative fuels such as hydrogen. Latin America is perfectly positioned to produce green hydrogen and become a hydrogen export hub. Mexico City, in particular, would greatly benefit from green hydrogen for mass transportation to reduce pollution and avoid price increases, such as the recent increase in diesel and gasoline prices due to higher oil prices resulting from the crisis in Ukraine

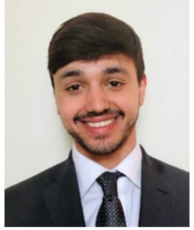
Authors

Nicolas Borda

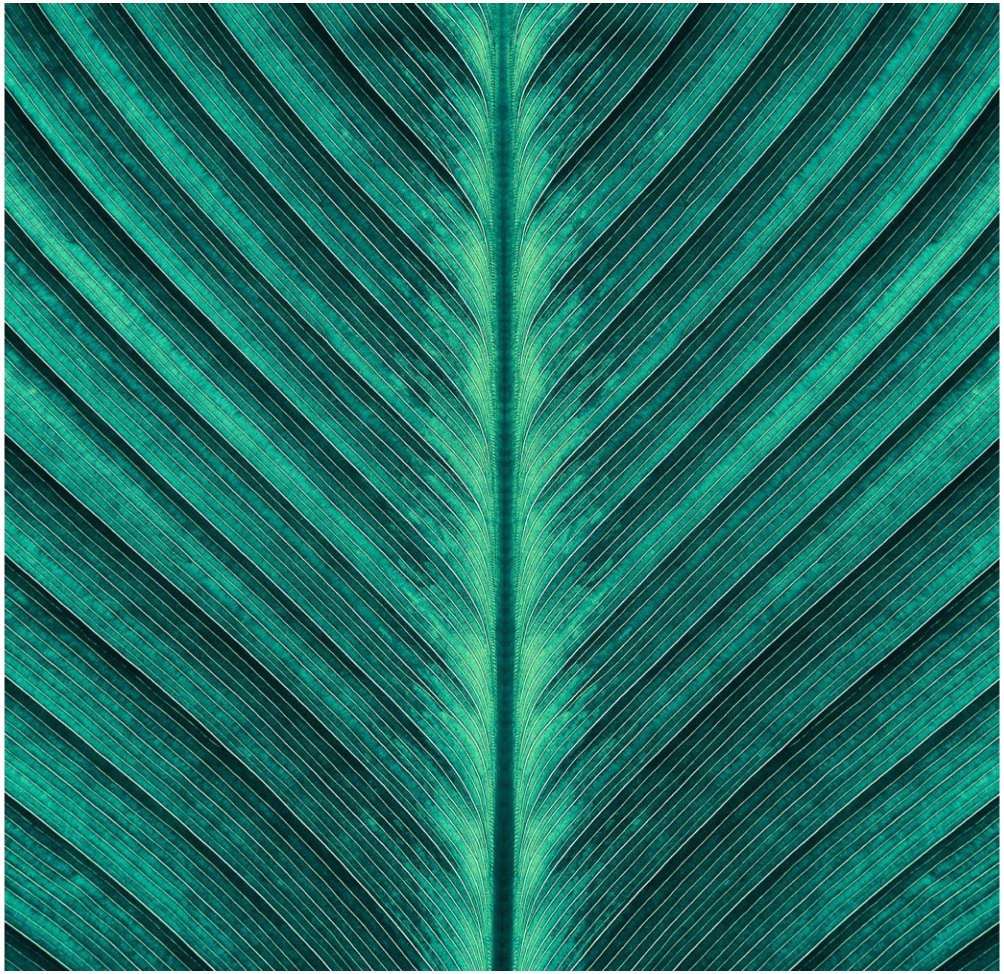


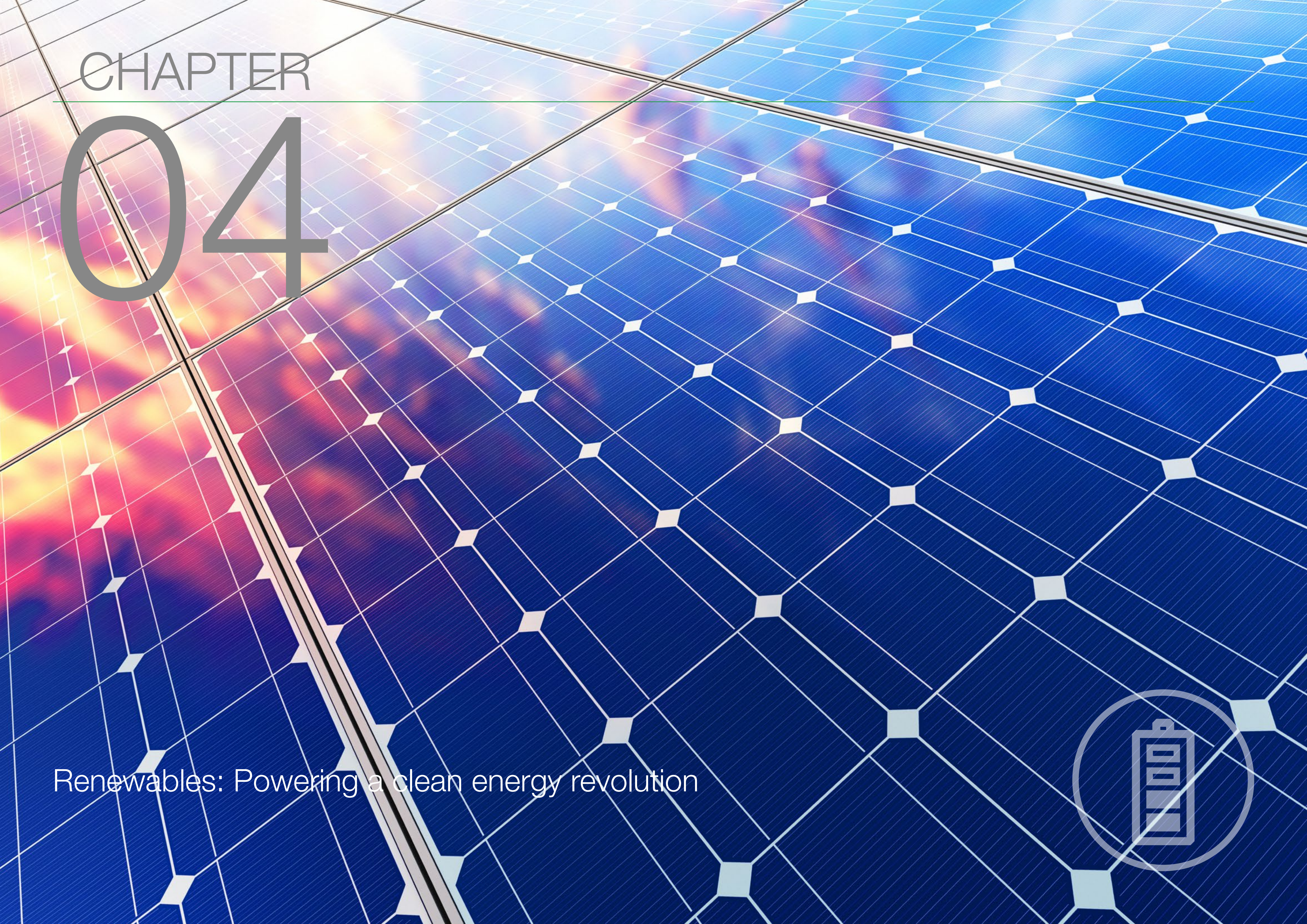
Nicolas is based in Reed Smith's Houston office and is an international business transaction lawyer with a focus on energy and natural resources, infrastructure, and Latin America. Nicolas focuses his energy practice on all facets of oil and gas (upstream, midstream, and downstream), power and renewable energy projects. He advises clients on international and cross-border transactions, regulatory matters, mergers and acquisitions, corporate, joint ventures, energy infrastructure project development, government procurement, public policy, anticorruption, compliance, HSE, NAFTA, USMCA, international trade, and dispute resolution in the energy sector. Nicolas has been involved in many energy projects and transactions throughout Latin America. Nicolas is ranked by Chambers Global and Chambers Latin America. Nicolas advises U.S. and international companies in all kinds of business and cross border transactions regarding natural resources.

Karim Alhassan



Karim is based in the Washington, D.C., office and focuses his practice on assisting clients with their compliance obligations regarding data privacy and security. More specifically, he has experience advising clients on their regulatory obligations stemming from emerging state privacy laws, as well as assisting in the defense of companies subject to regulatory investigations and actions by the Federal Trade Commission. Additionally, Karim has experience navigating the emerging and rapidly changing regulatory landscape in connection with digital assets, assisting on matters related to cryptocurrency advertising and under the federal securities laws.





CHAPTER 04

Renewables: Powering a clean energy revolution

Battery storage: Factors that may determine project viability

By Henry King, Brendan McNallen, Stephane Nguyen, Anna Karapetyan and Kevin Levy

Takeaways

- Battery storage enhances integration of intermittent renewable energy
- Project leaders should track lithium prices, effects of trade wars, COVID disruptions
- Contract and zoning rules could force storage projects to partner with power generators

One of the main challenges with wind and solar projects has been that energy production is intermittent. The fuel is free, but only available when the wind blows or the sun shines. In addition, wind and solar projects often produce electricity during periods when the market demand is not at its peak. Perhaps the most dramatic example of this issue occurs in the Texas market where wind projects generate during low-peak nighttime hours and are able to sell their output at negative prices because they continue to generate production tax credits.

Energy storage technology is poised to make a significant change in the economics of the electricity market, especially in markets where numerous wind and solar projects exist. As noted in National Renewable Energy Laboratory reports, the cost of battery technology continues to decrease and deployment is projected to grow by more than 500 percent by 2050 with over 125 GW of installed capacity.

The legal and contractual issues associated with development, construction, and operation of a battery storage project are similar to those of other power projects, but owners/developers should keep in mind some key issues, particularly around equipment supply contracts, real estate, and shared facilities.

Battery project developers should take into account the constantly evolving economic and political environments that impact procurement of energy storage equipment. For example, while the cost of battery technology may be decreasing in the long run, the rapid increase in demand for lithium, a key material in both utility-scale batteries and electric vehicle batteries, resulted in significant cost increases for battery storage equipment in 2021. Developers should consider how the risk of price increases or decreases should be allocated, particularly where there is a long period of time between execution of a contract and delivery of equipment under the contract. In addition, while the Biden administration revoked an executive order put in place by the Trump administration that would have prohibited the acquisition of certain equipment from foreign adversaries of the United States, it has maintained import tariffs established against China and could increase the tariffs as part of the ongoing trade war with China. At the same time, additional legislation may be developed as advocacy groups push governments to address human rights abuses associated with the extraction of minerals used in batteries. Since many battery manufacturers have operations located in Asia or other countries outside of the United States, developers should anticipate political uncertainty that could impact the cost of the equipment being supplied or the ability to source equipment or materials from certain countries.

Supply chain problems due to COVID-19 have impacted the ability of suppliers to timely deliver goods, including battery storage equipment. Although it has been nearly two years since COVID-19 broke out, new variants and surges in infection rates still threaten to disrupt global supply chains and logistics. Developers should ensure that each supply contract establishes a project schedule that takes into account the likelihood of such delays, allocates risk appropriately between disruptions that can be foreseen at contract execution and those that cannot, and provides for remedies that adequately compensate the developers for the impact of delays.

Another key issue with contracts is establishing clear criteria for supplier performance, particularly with respect to establishing commercial operation of the project and the ongoing performance of the energy storage system. Based on the technology of the battery system purchased and the requirements for a given project, developers should determine whether testing of one battery, a series of batteries, or the entire system of batteries is required to establish commercial operation of the project. Establishing clear criteria for such testing and requiring that payment be made to the supplier only after achievement of these criteria are also important, especially where a third party may be responsible for constructing a portion of the project.

Developers should also establish clear methods for assessing defective performance, and assessing remedies, over the course of the project lifecycle. This can be particularly nuanced given that battery performance naturally deteriorates over time and that the use of the battery is a factor driving the pace of deterioration. Developers should carefully craft remedies for defective products, including repairs that may be required during the operation of the battery system, maintenance of operating spares, self-help remedies, and cash payments. Such performance criteria and remedies are especially important where the battery system is incorporated into a larger renewable generation project, since the performance may impact more than just the individual battery system.

Large-scale battery storage projects are often sited adjacent to renewable generation projects. Developers may choose to structure these storage projects with separate project companies that will share real estate and infrastructure. The traditional contractual arrangement for shared facilities is a co-tenancy, where each project company has an “undivided interest” in the asset. These co-tenancy arrangements are not flexible in adding or changing the identity of the co-tenants, since that often requires the landowner or permitting agency to grant a separate right to a new project company.

Especially for large-scale, multi-phase projects, a more efficient structure is to use a limited liability company to own the shared asset, such as a generation tie-line or substation, and then have the project companies take partial ownership interest in the entity, which entitles the project company to use the asset. The limited liability company operating agreement will address issues such as funding of the improvements, curtailment, and a project’s potential interference with another project.

When determining the siting of battery storage projects, developers should consider issues relating to permitting and zoning. Due to their more compact nature, battery storage project sites often have a smaller real estate footprint than wind and solar energy generation projects. However, laws and ordinances often address permits and zoning of wind and solar projects, but have obvious gaps when it comes to battery storage projects. For example, the California Subdivision Map Act generally restricts the sale, lease, and financing of a portion of a parcel, unless the same has been legally subdivided, with limited exemptions. Renewable energy projects are often sited on portions of legal parcels for various reasons, including cost-effectiveness. The California Subdivision Map Act has exemptions for the leasing of land for solar energy generation projects and wind energy generation projects, which allow for such a structure. However, a similar exemption does not exist for battery storage projects, unless such projects are co-located with wind and solar projects and can be characterized as such for purposes of the Act.

Developers must be extra careful and consider the additional efforts required to comply with the California Subdivision Map Act, such as by reconfiguring boundary lines through a lot line adjustment or requesting a certificate of compliance from the local agency, both of which can add a considerable amount of time to project development. Developers should also consider obtaining a subdivision endorsement from the title company to insure compliance.

In addition, local zoning ordinances may not have yet incorporated battery storage into their provisions, and an ordinance that defines energy generation projects as a permitted use may make no mention at all of battery storage projects. In such a case, it may be unclear whether a zoning ordinance allows the construction and operation of a standalone battery storage project. This may force developers to allocate additional time and/or obtain special permits or variances for the project. Co-locating a battery storage project with another permitted use – such as a solar energy generation project – might be a solution to this issue, if the zoning allows for such a structure.

Battery storage projects also carry with them a risk of fire. As a result, local jurisdictions are often focused on minimization and mitigation of fire risks that may be implicated as a result of the construction and operation of such projects. When negotiating and obtaining site control agreements for projects, developers should ensure that they have the necessary real estate rights to comply with local fire risk mitigation requirements.

Battery storage projects continue to grow in size and quantity, with many utility-scale projects currently under development or planned over the next few years, and it is very important to consider the risks and issues that are specific to such projects.

Authors

Henry King

Henry is a partner in the Princeton office. His practice focuses on providing a broad range of advice to owners, investors and developers of energy generation projects of all types, focusing on renewable assets (onshore and offshore wind, solar, geothermal, biomass, battery storage), other new technologies such as fuel cell projects, as well as transmission projects. Henry has been involved in working with clients in the renewable energy industry since the late 1990s. A substantial amount of Henry's work relates to the purchase and sale of power plants. These transactions include both single and portfolios of projects, and occur both during the development stage and after commercial operation, including transactions for projects that will be repowered. Henry also represents projects in debt and equity transactions, including tax equity investments. Henry also handles all types of matters related to the development of power projects, including power purchase agreements, construction and equipment contracts, renewable credit sales agreements, O&M, asset management and construction management agreements, real estate and co-tenancy agreements, and wake impact agreements.

Brendan McNallen

Brendan is a partner in the Energy & Natural Resources Group in San Francisco. His practice focuses on project development and finance in the energy generation, energy storage, transmission and distribution and infrastructure sectors, with a specific focus on renewable energy. He represents developers, owners, manufacturers and lenders on the development, supply, construction and financing of onshore wind, offshore wind, solar and battery energy storage projects. Brendan also represents utilities on the procurement and construction of transmission and distribution facilities, procurement programs and program management activities. He has advised on energy projects throughout the United States and around the world, including Europe, South America, the Middle East, Mexico and Canada.

Stephane Nguyen

Stephane is a partner in the Century City office. His practice focuses on business law, with an emphasis on real estate and corporate transactions. His practice focuses on renewable energy (wind, solar and geothermal), energy storage and electrical transmission projects, where he regularly advises and represent sponsors, developers, owners, financiers, buyers and sellers of these projects. He has extensive experience with acquisitions, dispositions, financings and joint ventures of other real estate-based assets and businesses, including the asset classes previously noted as well as hotels, office buildings and commercial centers.

Anna Karapetyan

Anna Karapetyan is based in the Century City office. Her practice focuses on business transactional law, with an emphasis on real estate and corporate transactions. She represents developers, owners, buyers and sellers in transactions involving commercial real estate acquisition, disposition, financing, and sale-leasebacks. A large portion of Anna's practice focuses on the development, construction, and financing of renewable energy projects, including wind and solar energy and battery storage deals.

Kevin Levy

Kevin is based in the San Francisco office. His practice spans project development, M&A and finance in energy and infrastructure transactions, with a focus on renewable energy, including battery storage projects. He has extensive experience in negotiating and drafting deal terms, financing documents, and other ancillary documents. He has also represented early-, mid-, and late-stage private companies, public companies, investors, and underwriters in the technology and life sciences industries. Prior to becoming a lawyer, Kevin worked with tech startups and investors on a variety of sustainability and market growth projects.

Renewables projects: Structuring your construction contracts

By Laura Riddeck

Takeaways

- Interface issues between packages are critical – but an EPC solution is not always feasible
- Onshore/offshore splits can further complicate matters
- Success or failure of a project can be determined by how contracts dovetail

Governments around the world are increasingly investing in renewable energy projects as part of their strategic transition to clean energies. In this article, we take a look at some key considerations for structuring the construction contracts for such projects.

Package interfaces

Renewable energy projects typically involve a number of discrete key packages of work. In an onshore wind project, for example, the owner will procure the wind turbine generators and the balance of plant, comprising foundations, site roads, crane pads, and other infrastructure, as well as electrical connections to the grid, substations, and transformers. For offshore wind projects, the owner will additionally procure vessels and harbor facilities. On a solar project, multiple vendors may be appointed to supply key equipment with other contractors responsible for installation and interconnections. Where battery storage is required, the battery units will also be sourced.

Traditionally, due to the high values of proprietary vendor packages, these contracts have been independently procured, with the owner appointing each contractor separately and taking responsibility for the management of any interface between those contracts. Increasingly (particularly in relation to onshore wind and solar projects), owners are looking to appoint one contractor on an engineering, procurement, and construction (EPC) or “turnkey” basis.

EPC contracting is a long-established procurement route on many projects, including power generation. The advantage for the owner is that a single contractor takes on full responsibility for the management of all packages, including any interfaces.

Key interfaces on renewables projects often arise in relation to design and programming. On a wind project, for example, the turbine manufacturer’s load calculations need to feed into the foundation contractor’s civil engineering design so that the foundations can support the wind turbines within the environmental conditions at the site.

In addition to the management of the process, in the event of problems resulting from design errors, the structuring of the contracts may have implications for liability. With split contracts, any claim goes through the owner. One contractor would not claim against another, but instead would bring a claim against the owner, who then passes that claim on to another contractor. The owner therefore takes the insolvency risk for any package contractor, and any claims by one contractor that exceed the limit of liability of the other will fall to the owner. Liability is typically limited by reference to a percentage of the contract price, meaning that protection for any individual problem would be much lower in this scenario than under an EPC contract.

Management of delay is also critical. Delays in installation of one package can cause consequential delays in other packages. The owner would be smart to avoid being caught in the middle. Under an EPC contract, culpable delay by one of the package (sub)contractors would not entitle the EPC contractor to an extension of time. But with multiple packages, the owner would not be able to recover project-wide liquidated damages. Instead, the owner would claim delay damages from the delaying contractor and then would have to grant extensions of time (and, typically, cost) to the other contractors impacted.

A contractor's liability for delay will usually be liquidated. Delay damages need to cover the owner's own losses as well as any costs the owner incurs to other package contractors – but it is extremely difficult for an owner to price liquidated damages beyond its own losses. Delay damages would also usually be subject to sub-caps on liability, which derive from the applicable contract sum. Smaller packages will therefore have lower limits on liability, but may still have a significant impact.

A further complication is that these delays may not be linear – a one-week delay by a foundations contractor could turn into three weeks of delay for the turbine supplier as well as to the overall project. One week's delay damages may therefore be inadequate compensation for the owner in this regard.

It is easy to see why an EPC solution is attractive to an owner: one contractor delivers the whole project with responsibility for the interface issues as well as committing to project-wide completion deadlines and liability caps, giving the owner the potential ability to reject the entire project – including completed packages – if the solution ultimately does not work as warranted.

In some renewables projects, such as solar, EPC contracting is not uncommon. In the wind industry, it is seen much less frequently because of the large volume of proprietary equipment involved. Increasingly, owners are requesting an EPC structure for onshore wind projects. If any party takes the EPC risk, it would be the wind turbine manufacturer – the turbines, after all, are the highest package by value. Another contractor would likely add limited value beyond the contractual acceptance of risk.

But EPC risk – a big change in the traditional risk profile – is frequently unpalatable to turbine manufacturers. The owner is often seen as the best party to manage the interface risk. The owner is also the party who chose the site, has the best local knowledge, and is likely to be the best party to choose the contractors for the balance of plant (BoP). The manufacturer of the wind turbines generator, by contrast, is not a specialist EPC contractor with a regular BoP supply chain.

In an offshore setup, EPC solutions are even less likely to take off. There, the vessel packages add a further challenge (with vessel providers likely to offer limited flexibility in contracting terms), and the substation, foundations, and cabling packages are more complex.

Ultimately, the owner may be best placed to assume and manage the risk of multiple contracts. It may be a more cost-effective solution: any transfer of EPC risk would come with a premium. Split contracts can also be an advantage in terms of control and timing: you do not need to wait until everything is agreed upon before you can award some of the contracts.

Onshore and offshore splits

For tax purposes or to fulfill local requirements, another increasingly common issue for parties to work through when structuring these projects is a split in scope between onshore and offshore work. Onshore scope here means those elements of the scope that are to be performed within the project country (installation and commissioning, for example), whereas the offshore scope captures supply and manufacture outside of the country.

This issue is not unique to the renewables industry, but it is relevant given that such projects often involve a substantial part of the contract price representing payments for manufactured goods (such as wind turbine components, electrical equipment for transformers and substations, or modules and inverters) that need to be imported.

The driver here is usually tax, with the contractor seeking to avoid incurring local taxation on its offshore receipts when goods are being imported from outside the nation in which the project is being constructed. It arises most commonly in an EPC context, where the scope involves equipment supply plus on-site works and installation.

The result is that one contract is split into two, with the detail of the split often varying from jurisdiction to jurisdiction. Typically, the contractors will be the same entity or related entities.

The overarching aim here is that through the split contract, the parties should be in no worse (and no better) position than they would have been under a single contract. The devil is in the details, of course, and numerous complexities can be created (especially where the particular rules in the relevant jurisdiction mean that the contracts may not refer to each other). Common issues to work through include: dilution of liability limits defined by reference to contract prices (or, from the contractor's perspective, concerns over "double-dipping" with multiple contracts); how delay liquidated damages can compensate for the delay of the whole project; and interfaces and problems falling through the gaps.

These concerns are often addressed by an umbrella agreement, or "EPC wrap," a tri-partite agreement expressly dealing with such interface issues.

There is no "one-size-fits-all" solution since the requirements can vary considerably from jurisdiction to jurisdiction. We would always recommend obtaining specialist advice to ensure that an effective resolution is reached.

Final word

Multiple contracts are common in renewable energy projects – whether the project is divided by packages or into offshore and onshore split contracts. Where you have multiple contracts, how those contracts dovetail and respond in the event of project delay or external complications can be a major factor in the success or failure of the project.

Author

Laura Riddeck

Laura advises on construction and engineering projects within the Projects and Construction group at Reed Smith in London. Laura is recognized as a Rising Star by the London Super Lawyers List for Construction and Civil Engineering and is described by Legal 500 UK 2019 as "excellent" and is noted for being "very proactive in terms of offering solutions in a very practical way." Her experience encompasses a variety of energy and infrastructure projects with a particular focus on renewable energy developments. She is experienced in drafting and negotiating contracts based on FIDIC, NEC and other standard construction contracts, as well as bespoke EPC and other contracts, and focuses on providing commercial and effective solutions for clients.

Biden administration and FERC spur transmission development to support clean energy transition

By Colette D. Honorable and Debra A. Palmer

Takeaways

- Biden administration and FERC strive to upgrade U.S. electric transmission grid
- DOE and DOT finance and streamline construction of transmission lines
- FERC proposals aim to speed up the process of generator interconnection to the transmission grid

In keeping with the Biden administration's efforts to modernize the U.S. transmission grid and to support efforts to fight climate change, in August 2021, the Department of Energy (DOE) announced efforts to support transmission development in the West and on federally owned land in native communities.

To facilitate the construction of high-voltage transmission lines, DOE is offering two financing mechanisms:

- A $3.25 billion fund through the Western Area Power Administration Transmission Infrastructure Program to support project development and provide access to low-cost capital for transmission projects
- $5 billion in loan guarantees through DOE's Loan Programs Office to support innovative transmission projects along with transmission projects owned by federally recognized tribal nations or Alaska Native Corporations

The second offer focuses on high-voltage direct current systems, transmission lines to connect offshore wind, and facilities sited along rail and highway routes.

At the same time, the Department of Transportation (DOT) announced that it would develop guidance to facilitate the use of public highways and public rights-of-way that will assist in the development of transmission infrastructure and renewable energy projects and will also aid in the deployment of broadband and electric vehicle charging stations. This opportunity would ultimately spur interstate transmission project siting and permitting, which has been challenging at times. In April 2021, DOT issued guidance to provide clarity to state transportation departments in furtherance of supporting infrastructure development to spur clean energy development, among other national policy goals.

Interconnection reform

On June 17, 2022, the Federal Energy Regulatory Commission (FERC) issued a proposed rule on interconnection reform in Docket No. RM22-14 that follows up on a July 2021 advance notice of proposed rulemaking (ANOPR). This is the second proposed rule to result from the ANOPR, as FERC issued another proposed rule on transmission planning and cost allocation earlier this year in Docket No RM21-17. FERC approved the interconnection proposed rule in a unanimous vote.

By December 2021, there were more than 1,400 gigawatts of electric generation and storage pending in interconnection queues nationwide. On average, it takes more than three years for a project to become operational in most regions. To help address this backlog, FERC has proposed a series of reforms under Federal Power Act section 206, including the following.

Implementing a "first-ready, first-served" cluster study process. Current interconnection procedures employ a first-come, first-served serial study process in which a project is studied individually based on the order in which it submits a completed interconnection request. Under the proposed reforms, a transmission provider would enact a cluster study approach whereby the transmission providers would conduct larger interconnection studies covering multiple projects. Furthermore, the notice of proposed rulemaking would require interconnection customers to provide additional financial commitments and readiness requirements (such as increased study deposit amounts, site control demonstrations, and required commercial readiness milestones) to enter the interconnection queues. The proposed rule also suggests the imposition of withdrawal penalties to exit the interconnection queue process.

Expediting interconnection queue processing. Currently, interconnection procedures only require transmission providers to use reasonable efforts to meet the interconnection study time frames. Under the proposed reforms, the transmission providers would be subject to firm deadlines for the completion interconnection studies, and could face penalties for missing the deadlines (except in cases of force majeure). FERC also proposes establishing a standardized and transparent affected system agreement and specific modeling standards.

Interconnection sharing and colocation. FERC proposes to use standardized processes to allow multiple resources to share one interconnection request, and to allow colocation on a shared site behind one interconnection point. In addition, an interconnection customer would, in certain circumstances, be allowed to add a project to an existing interconnection request without losing its interconnection queue position. Currently, some transmission providers allow co-tenancy arrangements with a shared interconnection agreement, and some transmission providers do not.

The proposed reforms would also require a transmission provider to evaluate alternative solutions upon the request of an interconnection customer (to avoid network upgrades where possible), and also suggest updated modeling and performance requirements for nonsynchronous generation projects (for example, wind and solar). In particular, the proposed rule contemplates that these projects continue to provide power and voltage support during grid disturbances.

Comments on the June 17 proposed rule will be due 100 days after the proposed rule is published in the Federal Register, and reply comments will be due 130 days after its publication in the Federal Register.

Joint Federal–State Task Force on Electric Transmission

A number of FERC's interconnection queue reforms were highlighted during joint meetings of FERC and the National Association of Regulatory Utility Commissioners (NARUC). This unprecedented effort was undertaken to ensure cooperation between federal and state regulators, via a partnership between FERC and NARUC on electric transmission-related issues. The Task Force has focused on topics related to transmission planning and cost allocation, including transmission to facilitate generator interconnection, as well as high-voltage direct current transmission line development.

The Task Force was established in June 2021 in FERC Docket No. AD21-15-000. It is composed of all FERC commissioners and 10 state commissioner representatives, nominated by NARUC and affirmed by FERC. The Task Force has convened on three occasions in 2022, with all meetings open to the public and treated as formal proceedings

Authors

Colette D. Honorable

Colette leads the firm's Energy Regulatory group and is a member of the firm's executive committee. She is also a member of the firm's ESG group and is resident in the Washington, D.C., office. Colette is a highly regarded thought leader and strategist in domestic and international energy sectors. Colette recently served as Commissioner at the Federal Energy Regulatory Commission (FERC). She was nominated by President Barack Obama in August 2014, and unanimously confirmed by the U.S. Senate, serving from January 2015 until her term expired in June 2017. At the firm, Colette is a trusted advisor and counselor to several Fortune 500 energy companies, investor-owned utilities, renewable energy and technology companies. In this capacity, she provides strategic advice and counsel in a number of areas, including ratemaking matters, clean energy integration, performance-based ratemaking, achieving ESG goals and environmental justice issues. In her work, Colette supports clients working to mitigate the impacts of climate change, and also advises clients on the development and execution of inclusion strategies.

Debra A. Palmer

Debra is based in the Washington, D.C., office. Her practice focuses on energy regulatory matters, with an emphasis on matters involving the Federal Energy Regulatory Commission (FERC), state public utility commissions, and the federal courts. She has more 30 years of experience with federal regulatory issues facing the energy industry, and has assisted her clients in pursuing their goals before FERC, state regulatory agencies, and the federal appellate courts. Debra advises clients with varied interests in the energy & natural resources sector, including natural gas companies, local distribution companies, oil and gas pipeline companies, and electric utilities. Her ability to understand regulators' goals and present her clients' interests accordingly has helped her become a leading advocate for energy firms across the United States. Deb understands the interrelationship between operational, business, and regulatory concerns faced by the energy industry. She has cultivated a deep knowledge in these areas, earning a reputation as a trusted advisor in the planning, operating, financial, regulatory and reliability issues facing the rapidly changing natural gas and electric industries.

CHAPTER 05

Removing the obstacles to financing sustainable energy

Financing and taking security over emission allowances

By Patrick Sutton

Takeaways

- Carbon market participants are increasingly looking to monetize allowances as an asset capable of raising finance
- Legal regimes for allowances vary by jurisdiction
- Seek local legal advice regarding optimal security arrangements
- It should be possible to assign or charge UK allowances under English law

Carbon trading is increasingly prevalent. While traditional commodity market participants (for example, oil and gas majors, hedge funds, and banks) remain very active in this space, players from other economic sectors are joining as they seek to reduce their carbon footprints. The Taskforce on Scaling Voluntary Carbon Markets estimates that the market for carbon credits could be worth more than $50 billion as soon as 2030.

Participants pledge to offset their greenhouse gas emissions by trading voluntary carbon credits, such as UK allowances (UKAs) and EU allowances (EUAs). Both can be traded before being used (that is, applied to compensate for the emission of CO_2 or equivalent gases).

Voluntary allowances are generally eligible for trading by all economic sectors, not just sectors that are historically seen as emitting the most CO_2.

As with many types of assets, owners of carbon credits may wish to use them to obtain finance. This article considers how carbon credit owners may be able to secure their carbon credits in favor of a financier as security for a loan, just as a borrower would secure inventory over "physical" commodities – for example, oil in tanks or metals in warehouses – as collateral for a loan from its lender(s). However, given the intangible nature of carbon credits and their relative novelty as an asset class, legal regimes around carbon credits differ from those around physical commodities. Financiers should get themselves comfortable with these regimes in order to determine whether they are capable of having a valid and enforceable security interest over the relevant financed carbon credits.

The type of security that is capable of being taken over a particular asset will generally depend on the location of that asset, and the legal regime in that location, but as a starting point, it would generally be recommended that the governing law of the relevant security document would be the legal regime where the asset is located. This article primarily considers the position in respect of UKAs under English law.

The English courts have determined that EUAs are a form of "other intangible property." However, since the creation of the UK Emissions Trading Scheme (UK ETS), the English courts have not considered the legal nature of UKAs, nor have they determined whether the EUA is a "chose in action" (that is, a debt or rights under contract).

Given that the UK ETS largely mirrors the EU Emissions Trading Scheme (EU ETS) framework, and in absence of anything further in the UK statutory framework that elaborates on the legal nature of UKAs, we believe English courts are likely to adopt the same approach as the Europeans when considering the legal nature of UKAs.

If UKAs can be characterized as a chose in action, a security interest can be taken over them by an assignment by way of security. This assignment can be legal or equitable.

Should the English courts decide that UKAs in a UK Registry account are not choses in action, the assignment of the UKAs would be invalid. Accordingly, the financier would wish to have a charge in respect of the UKAs in the counterparty's UK Registry account, as well as the account itself.

Any asset that is recognized as "property" can be subject to a charge, including intangible property. Charges can either be fixed or floating.

In order to take an effective fixed charge over the UKAs in a UK Registry account, and the account itself, the financier would require strict restrictions on the counterparty's ability to deal with the UKAs and the account. Based on our understanding of the UKAs and the UK Registry account from a practical perspective, we do not believe that a financier would have adequate factual control to achieve a fixed charge over these assets. In this situation, the lender can take security over the UKAs in the UK Registry account, and the account, by way of a floating charge.

An alternative approach worth possible consideration is that the counterparty place the UKAs with a custodian and the financier take security over the counterparty's rights against the custodian.

Under this arrangement, the counterparty would enter into a custody agreement with the proposed custodian. The lender would then take an assignment (by way of security) of such a custody agreement. In this case, the UKAs would be held in a UK Registry account in the name of the custodian and the lender's security would be over the counterparty's rights against the custodian under the custody agreement, including rights to require the custodian to deliver up the EUAs held for it in custody. In order to perfect such an assignment, notice must be given to the custodian.

If the financier wished to enforce the security assignment, the financier would request the custodian to deliver to the financier the UKAs held for the counterparty.

Whilst we are aware that some companies offer custodian services for EUAs, we are not currently aware of any companies offering these services for UKAs.

In each instance, security granted by an English entity generally should be perfected by registering the security document at Companies House within 21 days of the creation of the security. Otherwise, the security will be void on the insolvency of the counterparty.

We look forward to seeing how different legal regimes continue to characterize carbon credits and to assisting lenders and borrowers in navigating these challenges.

Author

Patrick Sutton

Patrick is a partner in the firm's global Energy & Natural Resources Group in London. He focuses on trade and commodity finance, and sports finance, and his practice covers a variety of financing structures across emerging and developed markets. Patrick's work in the commodity finance area covers a range of products, including: borrowing base, pre-export, and prepayment facilities, receivables structures (including receivables discounting and supply chain finance), and title based structures (including repos and inventory monetization). Increasingly, Patrick works on structured finance products in the trade and commodity space, and was a leading adviser on the market's first trade finance lending ABS program. Patrick is a member of the firm's ESG Group, and has a particular focus on sustainable finance, the energy transition, and the financing of carbon.

Environmental, social and governance considerations in sustainable finance decisions

By Daniel Buoniconti

Takeaways

- Sustainable finance means taking ESG into account when making investment decisions in the financial sector
- The sustainability criteria and related benefits and penalties vary by facility and borrower and are negotiated on a facility-by-facility basis
- Rendezvous clauses in facilities provide flexibility to change provisions as market standards evolve

Sustainable finance involves taking environmental, social and governance (ESG) considerations into account when making investment decisions in the financial sector.

Environmental considerations capture a broad range of factors, including biodiversity, climate change, pollution mitigation, and more. Social considerations include issues of inequality, inclusiveness, labor relations, investments in communities, consumer rights, and human rights. Governance factors address the management, employee relations, and compensation practices of both public and private organizations.

Over time, sustainable finance can stimulate the flow of private investment into the transition to a climate-neutral, resource-efficient economy. Investment is up in businesses and projects that follow sustainable ESG practices, and demand is also up for finance professionals with expertise in this niche field. We foresee similar growth in the legal services field as borrowers and lenders rely on counsel to properly evaluate and effectively advise on relevant issues and existing standards in these areas.

Provisions addressing ESG and sustainability finance can vary widely across facilities as different lenders have developed their own template languages. The potential benefits and penalties of these sustainability mechanics vary by facility and borrower.

In our experience, however, some common features are usually present. A lender (or a group of lenders) typically acts as the sustainability coordinator. Facilities generally include an adjustment to the applicable margin, known as the sustainability margin adjustment. The sustainability margin adjustment is negotiated as a commercial term between the parties and can increase or decrease the applicable margin of a facility depending on the borrower's performance in connection with defined sustainability criteria during a certain period. Typically, the borrower will deliver a certificate from time to time, under which it vouches for its performance in accordance with the applicable sustainability criteria and the sustainability margin adjustment.

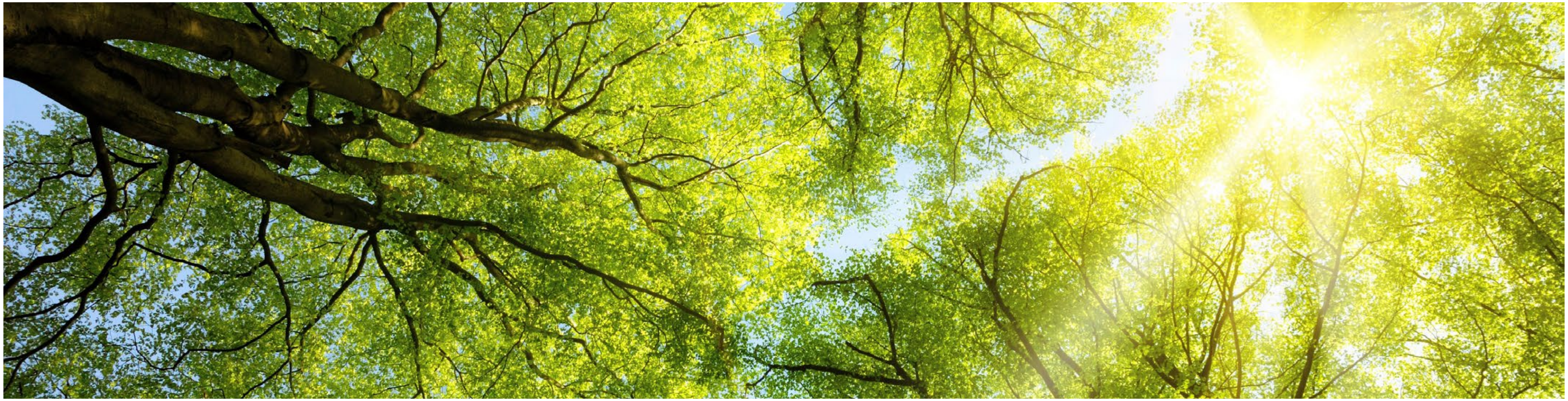
The sustainability criteria and related benefits and penalties vary by facility and borrower, and these are negotiated on a facility-by-facility basis. As we continue to prepare additional facilities containing these legal components, more frequent market standards and applications will emerge. The evolving market standards have inspired parties to include a rendezvous clause in facilities, which provides flexibility to change facility provisions as market standards evolve. A rendezvous clause enables the parties to operate in good faith to address and accommodate potential substantive changes to the methodologies or standards in place at the time of the initial agreement.

This burgeoning area within the financial markets will continue to expand in importance and capacity in 2022 and beyond. Reed Smith will continue to work at the forefront of this area by negotiating market-leading transactions featuring these standards and provisions.

Author

Daniel Buoniconti

Dan is a partner in the firm’s Energy and Natural Resources Group in Chicago. He concentrates his practice on trade finance, structured finance, receivables finance, inventory finance, and commercial lending. Dan advises clients in connection with international and domestic securitizations, receivables discounting facilities, revolving and term credit facilities, borrowing base facilities, repo and consignment transactions, and bilateral facilities. He also represents clients in connection with commercial arrangements involving the use of logistical assets for the storage, transportation, and processing of physical commodities.



CHAPTER 06

Training menu

Training menu

Bespoke training sessions

Topics cover key trends in the energy and commodities sector

Our lawyers offer bespoke training sessions on key topics and emerging legal issues in the energy and commodities sector. Complete our bespoke training form to express your interest in any of the topics below, or to request a session on a particular area of focus.

We deliver training in many formats, from traditional presentations, to more interactive "teach-in" sessions and informal discussion/ sharing of ideas. Sessions can be delivered in-person or remotely via Zoom or another preferred platform

What will be covered:

01

SUPPLY CHAIN ISSUES

Richard Swinburn / Terry Prempeh

- How unsustainable supply chains impact businesses
- Value gained from managing ESG risks in supply chains
- Agri-commodities: How to manage supply chain risks
- Extractive commodities: how to manage supply chain risks
- Global legislation trends toward ESG
- How is the market reacting to ESG management?

02

HYDROGEN TRADING AND TRANSPORTATION

James Atkin / Nicole Cheung / Tom Watling

- Introduction to hydrogen: What is it and why is it attractive as an energy source?
- The hydrogen market: The current state of play
- The regulatory landscape: How to regulate an explosive and flammable gas
- How will hydrogen documentation develop?
- Factors to consider when transporting hydrogen
- Future-proofing: The complications of a new market

03

CARBON TAX, EU REDUCTION STRATEGIES AND NET ZERO COMMODITIES CONTRACTS I

FOR MARKET ENTRANTS

Adam Hedley / Yves Melin / Natalia Debowska

- The different categories of carbon credits: Avoided nature loss, nature-based sequestration, avoidance of emissions and removal of CO_2 from the atmosphere
- Differences between the voluntary and regulated market
- Voluntary standards: How they are aligned with the regulated market and how businesses can ensure the integrity of a carbon offset in a voluntary market
- Key considerations: A look at spot and futures trading
- Drafting 101: How to effectively draft documentation, available templates and risks to keep in mind
- Broader industry concerns: The lack of a standardized protocol for measuring, advertising and marketing compliance and what is a “carbon-neutral” commodity?

04

CARBON TAX, EU REDUCTION STRATEGIES AND NET ZERO COMMODITIES CONTRACTS II

SOPHISTICATED MARKET TRADERS

James Atkin / Adam Hedley / Yves Melin / Mira Dandan

- Documentation: How to improve drafting, clauses to consider, risks and lessons learned from recent disputes
- Growth of “morality” clauses in carbon credit agreements
- Projects generating credits: The avoidance or reduction of greenhouse gases and the removal or capture of CO_2
- Carbon offsetting through being the primary offtaker of units from a project
- Greenwashing concerns and how to maintain reputational risk
- Broader industry concerns: The lack of standardized protocol for measuring, advertising and marketing compliance and what is a “carbon-neutral” commodity?

05

FLASH TITLE TRANSACTIONS

Elizabeth Farrell / Christos Antoniou

- Documenting your flash title transactions in commodity structured trade finance
- Flash title transactions [document options, specific market (e.g. LNG) and price hedging]
- Legal and operational alignment in back-to-back transactions (notices, netting and shipping documents)
- Counterparty jurisdictional risk: What are the local laws?
- Does the “polluter pays” approach apply to your flash title transaction?
- Confirmation notice disputes: One arbitral tribunal or two?
- Managing your day-to-day obligations

06

INVENTORY MONETIZATION

Dan Birch / Terry Prempeh

- What are the consequences of commingling?
- What is the re-characterization risk?
- How to determinate a transaction: What are the local laws?
- Rights and obligations under the storage arrangements
- Environmental risk: How to spot potential risks and liabilities

07

STORAGE OF COMMODITIES

Elizabeth Farrell / Bartek Rutkowski

- Title and commingling
- Warehouse receipts and holding certificates
- Liens and pledges
- Collateral management agreements and stock monitoring agreements
- Insurance
- Floating storage and STS
- Regulatory and environmental issues
- General practical tips

08

INSURANCE OF COMMODITIES

Frances Furness / Terry Prempeh

- Identifying (and insuring) the relevant risk
- Placing the policy: Fair presentation of the risk
- Placing the policy: Contract terms
- Operating the policy effectively following a loss
- Thoughts on the role of brokers

09

TRANSACTIONS – "HOT TOPICS" TOKENIZATION AND DISTRIBUTED LEDGERS

Paul Skeet / Natalia Debowska

- Drivers underpinning the tokenization of commodities
- Issues relating to the safety/ integrity of the token platform operator
- Documenting the relationship between the platform operator and purchasers
- The legal framework surrounding the value of tokens

10

LESSONS LEARNED FROM COMMODITIES FRAUD

Elizabeth Farrell / Rob Allan

- Bill of Lading-related fraud
- Warehousing and warehouse receipt-related fraud
- Invoicing fraud and cyber fraud
- Remedies and enforcement tools (including equitable tracing and freezing orders)
- How to mitigate the risk of fraud

11

TRENDS IN LNG DISPUTES I

TERM SUPPLY ARRANGEMENTS

Frances Furness / Nick Moon

- Big picture trends: How is the market changing?
- Take-or-pay, Deliver-or-pay: The character of the contract, failure to deliver requirements to mitigate and evidence costs
- Destination restrictions: What you should be aware of
- Pricing in the European and Asian markets

12

TRENDS IN LNG DISPUTES II

SPOT TRADING

Frances Furness / Nick Moon

- What to do when a cargo is off-spec?
- Creditworthiness and counterparty risk
- Failure to deliver: Liability caps
- Force majeure: Is there a market standard clause?

13

DISPUTES: OFFERS IN MITIGATION

Frances Furness / Terry Prempeh

- The purpose of an "offer in mitigation"
- Timing of the offer
- Nature/certainty of the offer
- Is there an available market?
- Impact on other legal remedies

14

DISPUTES: UNPAID SELLER'S REMEDIES

Andrew Meads / Tiffany Georgalides

- English Sale of Goods Act remedies
- Why is the definition of "insolvency" so important?
- The right of stoppage in transit
- The effect of an "on-sale" and the unpaid seller's right of "re-sale"
- The interplay of statutory remedies with contractual remedies
- Spotlight on contractual remedies in industry standard forms

Reed Smith LLP is associated with Reed Smith LLP of Delaware, USA and the offices listed below are offices of either Reed Smith LLP or Reed Smith LLP of Delaware, USA, with exception of Hong Kong, which trades as Reed Smith Richards Butler.

All rights reserved.

Phone: +44 (0)20 3116 3000
Fax: +44 (0)20 3116 3999
DX 1066 City/DX18 London

ReedSmith

Driving progress
through partnership

reedsmith.com