CJP CLIMATE JUDICIARY PROJECT™

ENERGY AND LAW FOR JUDGES

Making Energy: *Legal Processes and Frameworks for Energy Projects*

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Making Energy: Legal Processes and Frameworks for Energy Projects

by David Spence*

This module outlines the life cycle of an energy project in the United States. It surveys the laws and legal issues that apply to siting, financing, permitting, public participation, operation and ongoing compliance, and decommissioning these projects.

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I. Energy Project Development and Siting, Generally

Building new energy infrastructure is an expensive, time-consuming, and politically fraught endeavor, not only for merchant developers, but also for monopoly investor-owned utilities (IOUs). Most energy projects are capital-intensive, long-term investments that most people would prefer be built somewhere other than their own neighborhoods. Furthermore, the legal regimes that regulate development of energy infrastructure are not an organic whole; rather, they are a hodgepodge of statutes that have accumulated over many decades, each focused on specific technologies and/or controlling specific types of risks, like pollution. Together, they constitute what scholars call a "regulatory anticommons" in which the power to approve or disapprove of any single energy project is spread across multiple government bodies at the federal, state, and local levels.[1] This means that any energy project must pass through multiple veto gates, each requiring satisfaction of its own set of standards.

For investors, the initial decision to build an energy infrastructure project at location X and time T is an economic one. But project economics are strongly influenced by legal and sociopolitical factors that are time-, place-, and technology-specific. ExxonMobil's decision to invest in oil exploration in Texas will involve a very different calculation, both economically and sociopolitically, than a small independent oil company's decision to invest in oil production in Colorado. And both are very different from Pacific Gas & Electric's decision to invest in a new solar farm in California, which in turn is different than a small non-utility startup's decision to invest in solar in North Carolina. And so on. More generally, the business case for each decision in each location is shaped by (i) the project sponsor's cost of capital, (ii) the market conditions for the energy service provided by the project at that time and place, (iii) the legal regimes that govern entry into the market for that kind of project in that location, and (iv) what developers call the "social license to operate" in the proposed project location—the various forces that influence public attitudes toward the project, which in turn can influence the content of applicable legal regimes, the way those regimes are administered, and therefore the ultimate cost of the project.

For developers of energy projects of all kinds, maintenance of this social license to operate is an increasingly important part of the project development process, perhaps because modern technology allows local opponents to mobilize opposition so much more efficiently than in the past. After technological improvements in the process of hydraulic fracturing made production of oil and gas from shale deposits much cheaper in the early 2000s, opposition to fracking spread very quickly in the 2010s, producing bans on the practice in four states and hundreds of local government jurisdictions.[2]

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[1] William Buzbee conceived a "tragedy of the regulatory commons" in which jurisdictional gaps can be exploited by firms. William W. Buzbee, *Recognizing the Regulatory Commons: A Theory of Regulatory Gaps*, 89 IOWA L. REV. 1 (2003). The regulatory anticommons involves jurisdictional overlap producing too many veto rights over a regulated activity. *See, e.g.*, Lea-Rachel Kosnik, *River Basin Water Management in the U.S.: A Regulatory Anticommons*, 5 ENV'T & ENERGY L. & POL'Y 365 (2010); Giuseppe Beallantuono, *The Regulatory Anticommons of Green Infrastructures*, 37 EUR. J. L. ECON. 325 (2014); Michael A. Heller, *The Tragedy of the Anticommons: Property in the Transition From Marx to Markets*, 111 HARV. L. REV. 621 (1998).

[2] Christopher J. Hilson, *Litigation Against Fracking and Moratoriums in the United States: Exit, Voice and Loyalty*, 40 WM. & MARY ENV'T L. & POL'Y REV. 745 (2016).

Likewise, the rapid development of inexpensive wind and solar energy more recently has triggered a similar reaction, and formal or de facto bans on wind and solar development in hundreds of counties.[3]

When locals object to hosting new energy infrastructure projects, their resistance often triggers jurisdictional conflicts with state or federal regulators who propose to authorize the projects. For conflicts that pit a federal licensing regime against state or local opposition, courts apply Supremacy Clause preemption jurisprudence to ask: (1) if a federal statute has expressly preempted the exercise of state law, and if not, (2) if a federal statute "occupies the field" leaving no room for state regulation, or (3) if compliance with the state statute would prevent compliance with the federal law.[4] If the answer to any of these questions is "yes," then the federal statute controls. For conflicts that pit state law against local opposition, the analysis is a bit more complicated. It often begins by (a) acknowledging Dillon's Rule, the notion that local governments are subdivisions of the state and can exercise only the powers the state delegates to them, and (b) asking if the state has delegated "home rule" powers to the local government in question. These inquiries, in turn, are often analyzed by state courts under doctrinal rules that mirror the federal preemption analysis: looking first for language in the applicable state statute that suggests an answer, and then at the intent or purpose of the statute if the statute does not expressly preempt the local law.[5]

II. Financing Energy Projects

A. Investor-Owned Utility Project Financing

The financing of projects built by monopoly investor-owned utilities, such as IOU-owned natural gas pipelines, power plants, or transmission lines—is heavily shaped by ratemaking and cost recovery principles built into public utility law. Federal and state public utility statutes allow the IOUs to pass through project costs (plus a fair return on investment) to captive ratepayers, but charge the Federal Energy Regulatory Commission (FERC) and state public utility commissions (PUCs), respectively, with protecting ratepayers by ensuring that ratepayer-financed investments are both *prudent* and *used and useful* for the provision of the regulated energy service.[6] Despite these ostensible protections, academic commentators worry that these principles have been applied poorly at certain times and places, and that the guarantee of a fair return on investment offers IOUs an incentive to overinvest in

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[3] Elizabeth Weise, *Across America, Clean Energy Plants Are Being Banned Faster Than They're Being Built*, USA TODAY (Feb 04, 2024), https://www.usatoday.com/story/news/investigations/2024/02/04/us-counties-ban-renewable-energy-plants/71841063007/. *See also* MATTHEW EISENSON ET AL., OPPOSITION TO RENEWABLE ENERGY FACILITIES IN THE UNITED STATES: JUNE 2025 EDITION, SABIN CTR. CLIMATE CHANGE L. (2025).

[4] *See, e.g.*, David B. Spence *Federalism, Regulatory Lags, and the Political Economy of Energy Production*, 161 U. PA. L. REV. 431 (2013), https://pennlawreview.com/2013/01/29/federalism-regulatory-lags-and-the-political-economy-of-energy-production/.

[5] David B. Spence, *The Political Economy of Local Vetoes*, 93 TEX. L. REV. 351 (2014), https://texaslawreview.org/wp-content/uploads/2015/08/Spence-93-2.pdf; Michael B. Gerrard & Edward McTiernan, *State Authority to Preempt Local Laws Regulating Renewable Energy Projects*, 259(90) N.Y.L.J. (May 10, 2018), https://scholarship.law.columbia.edu/faculty_scholarship/3059.

[6] For an application of both these principles, *see* Jersey Central Power & Light Company v. Federal Energy Regulatory Commission, 810 F.2d 1168 (D.C. Cir. 1987); and Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989).

capital, a phenomenon known as the *Averch-Johnson effect*.[7] See Introduction to the U.S. Energy System for more detail on public utility ratemaking standards and considerations.

B. Merchant Project Financing

Non-utility or "merchant" energy projects include projects that have always been outside the public utility law regime, such as coal mines and oil and gas wells, as well as merchant power plants built in places where electricity markets have been restructured in recent decades. Electricity market restructuring (covered in greater detail in Introduction to the U.S. Energy System) refers to the breaking up of the vertically integrated business model used by utilities, where they owned all aspects of the energy supply chain, including generation, transmission, and distribution. Restructured electricity markets, in turn, include both fully competitive power markets like those found in the ISONE (Independent System Operator New England), NYISO (New York Independent System Operator), PJM (PJM Interconnection) and ERCOT (Energy Reliability Council of Texas) grid regions, as well as hybrid markets where regulatory commissions regulate retail but not wholesale prices—places like the MISO (Midwest Independent System Operator) and SPP (Southwest Power Pool) regions (see Figure 1).

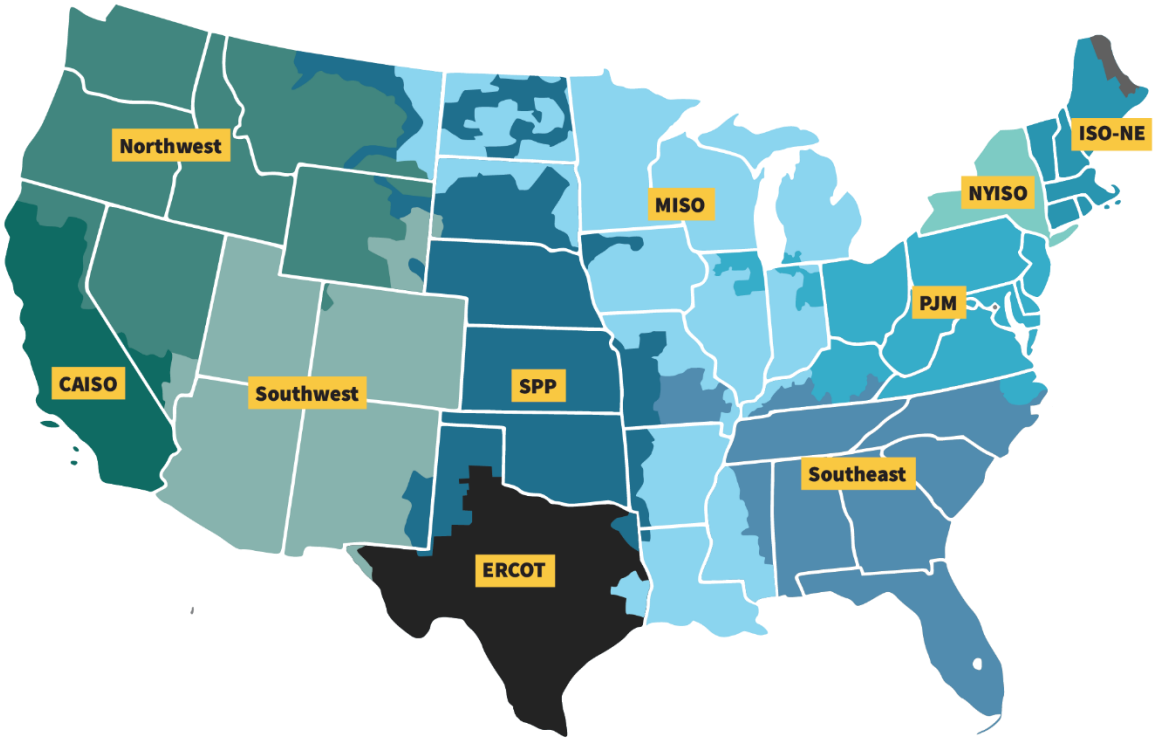

Figure 1. Map of Regional Transmission Organizations and Independent System Operators. Source: FERC, *RTOs and ISOs* (last updated Jan. 17, 2024), https://www.ferc.gov/power-sales-and-markets/rtos-and-isos.

[7] Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962).

Merchant energy project developers must attract investment capital without the benefit of captive customers and a legally guaranteed fair return on investment. In such cases, prospective investors want to maximize revenue certainty (or predictability), so developers usually finance the project on the back of the revenue stream created by contracts to sell energy from the project. For example, most merchant power plants are financed based upon one or more power purchase agreements (PPAs) with a utility or other electricity retailer. Prospective investors are more likely to invest, or to invest more, if they can foresee a guaranteed revenue stream from PPAs.

Of course, financing an energy project is easier, all else equal, if the project can sell its energy at more favorable rates. Thus, oil exploration and production is easier to finance when the market price for crude goes up; similarly, the recent spike in demand seems to be driving electricity prices upward, attracting investors to new power plant projects. Localized price spikes caused by bottlenecks in energy delivery systems (pipeline or transmission networks) also incentivize new investment in those locations. Likewise, projects with a more *predictable* revenue stream are more easily financed, all else equal. One reason why wind and solar projects have dominated the market for new power plants is that investors know that their power will be first in the dispatch queue; system operators must prioritize connecting to the grid projects with the lowest marginal costs, making their revenue streams more predictable than that of, say, a gas-fired power plant in the same location. See Introduction to the U.S. Energy System for additional context on the interconnection queue and how system operators prioritize projects.

Finally, the ability to access more than one revenue stream also helps a project's ability to attract investment capital, all else equal. For example, some electricity markets make it easier than others for grid-based batteries to earn revenues from power sales, or to earn revenue from the provision of power reserves (even if they go unused) and other services. Similarly, a gas-fired power plant is easier to finance in places where it has a chance to sell both its power and its reserve capacity (see Box 1), as it can in PJM, NYISO and ISONE (but not ERCOT). The different regional wholesale markets each have their own rules governing these issues, making certain kinds of projects easier to finance in one place than another.

Box 1. Project Revenue Streams

Charges for Electricity = money paid for energy (kilowatt-hours) used by consumers.

Charges for Reserve Capacity = money paid to power plants (or battery storage facilities) simply for being available to meet potential demand, with their generating capacity (kilowatts) turned off but ready to add to the grid should those resources be needed.

C. Other Policy Influences on Financing

Beyond these general principles, the financing of specific types of energy projects can be helped or hindered by the policy environment.

1. Tax Subsidies

Where applicable, tax deductions and tax credits reduce energy project costs, making the project more profitable all else equal. For most of the last half-century, federal and state governments have (at one time or another) provided tax subsidies for almost every kind of energy project, though the strength of each has varied over time. An exhaustive list of energy tax subsidies is beyond the scope of this module,[8] but some of the most prominent include fossil fuel tax deductions such as the deduction for intangible drilling costs[9] and the oil and gas well depletion allowance,[10] and investment tax credits and production tax credits for renewable and other green energy projects. Prior to the 2022 passage of the Inflation Reduction Act (IRA),[11] those credits took the form of an up-front investment tax credit for solar projects and a production tax credit (per kilowatt hour of delivered electricity) for wind projects.[12] The IRA extended the investment tax credit to a wide variety of investments associated with the clean energy transition (beyond wind and solar projects), and to a broader array of eligible taxpayers.[13] However, many (but not all) of those IRA provisions were repealed in the One Big Beautiful Bill Act of 2025 (OBBBA).[14]

2. Direct Subsidies

Some merchant energy projects also benefit from direct subsidies like grants, government loans at favorable rates, and liability limitations. As with tax subsidies, the number of direct subsidies for energy projects are too numerous to list here. One of the largest direct subsidies for energy project development dates back to 1957: the Price-Anderson Act,[15] which limits the liability of nuclear power plant owners in the event of a nuclear accident (to approximately $15 billion). Some unrepealed parts of the IRA provide grants and low-interest loans for energy projects. Some direct subsidy provisions from older laws remain on the books, but those are mostly unfunded. Those older laws include: (a) the

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[8] The U.S. Energy Information Administration (EIA) has provided a more complete analysis of U.S. energy subsidies in U.S. EIA. *See* Federal Financial Interventions and Subsidies, 2016-2022 (August 2023), at https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

[9] 26 C.F.R. §1.263(c)-1.

[10] 26 C.F.R. §613.

[11] Inflation Reduction Act of 2022, H.R. 5376, 117th Cong. (2022).

[12] For a history of these green energy credits, *see Alternative Energy Tax Incentives: The Effect of Short-Term Extensions on Clean Energy Investment, Domestic Manufacturing, and Job Creation: Hearing Before the Subcomm. on Energy, Nat. Res., and Infrastructure of the Sen. Comm. on Fin.*, 112th Cong. 5 (2011) (statement of Molly Sherlock, Analyst, Cong. Rsch. Serv.):

> When first enacted in 1978, the renewable energy investment tax credit was scheduled to expire at the end of 1982. In 1980, the credit rate was increased and the duration of the credit extended, through the end of 1985. The investment tax credit for solar was allowed to lapse at the beginning of 1986, before being retroactively extended through the end of 1988. The credit was again extended in 1989 and 1991. In 1992, the 10% investment tax credit was made permanent.

[13] For a summary of the Act's provisions, *see* U.S. EPA, *Summary of Inflation Reduction Act Provisions Related to Renewable Energy*, (last updated July 8, 2026), https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy.

[14] Pub. L. No. 119-21 (2025). For a comparison of some of the tax credits and changes in the OBBBA, including for carbon sequestration, electric vehicles, biofuels, clean hydrogen, energy efficiency in buildings, and more, *see* Shane Londagin & Avi Zevin, *A Brief Overview of Major US Clean Energy Tax Policy (2005-2025)*, THIRD WAY (July 18, 2025), https://www.thirdway.org/graphic/a-brief-overview-of-major-us-clean-energy-tax-policy-2005-2025.

[15] Price Anderson Nuclear Industries Indemnity Act of 1957, Pub. L. No. 85-256, 71 Stat. 576, 23 U.S.C. ch. 23.

Energy Policy Act of 2005,[16] which added lucrative grants and loan guarantees for investments in energy efficiency, nuclear power, "clean coal," biofuels, and hydrogen-powered vehicles; (b) the Energy Independence and Security Act of 2007,[17] which established subsidies for energy efficiency and biofuels; and (c) the American Reinvestment and Recovery Act of 2009,[18] which created financial support for energy efficiency, renewable energy, and biofuels.

3. Demand-Forcing Policies

The U.S. Congress and the states have periodically enacted policies that drive increased demand for certain kinds of energy, thereby enhancing the economic case for those projects. The Public Utility Regulatory Policies Act of 1978 (PURPA)[19] created a market for electricity from non-utility-owned[20] (merchant) "alternative" energy projects,[21] by requiring IOUs to buy power from these projects.[22] In so doing, PURPA incentivized the first generation of wind farms in the United States, as well as hundreds of new small hydroelectric projects, and other first-generation utility-scale clean energy projects. In states that retain (unrestructured) traditional IOU monopolies, this PURPA mandate continues to aid the financing of merchant power projects.

States are another source of policy-driven demand for clean energy. Many have enacted "renewable portfolio standards" (RPS) that require electricity retailers (IOUs or competitive retailers) to procure a specified percentage or amount of electricity from renewable sources.[23] In recent years, some state RPSs have been broadened into "clean energy standards" (CES) that specify carbon emissions targets and/or apply to other sectors of the state economy beyond electricity. As of this writing, there are 30 states with RPSs or CESs. Within the last five years, several states have established aggressive targets

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[16] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (codified in scattered sections of 42 U.S.C.).

[17] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, 121 Stat. 1492. (codified as 42 U.S.C. §§17001-17386).

[18] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5, 123 Stat. 115.

[19] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 7 U.S.C., 15 U.S.C., 16 U.S.C., 42 U.S.C., and 43 U.S.C.).

[20] In the parlance of the statute, these facilities were called qualified facilities (QFs) in that they met the statutory definition of types and sizes of generating plants. These QFs were entitled to sell their power to utilities at the utility's avoided costs.

[21] PURPA defined "alternative" energy facilities to include various forms of renewable energy like solar, wind, and geothermal, as well as small hydroelectric facilities and cogeneration plants. Cogeneration facilities produce electricity as well as usable heat energy, and most of the many hundreds of cogeneration facilities built after the passage of PURPA in the 1980s were gas-fired. 16 U.S.C. §824a-3 (2006).

[22] Importantly, Section 210(b) of PURPA required that these purchases be at just and reasonable rates, which cannot exceed "the incremental cost to the electric utility of alternative electric energy" (avoided cost). 16 U.S.C. §824a-3(b). This language restricts states from subsidizing clean energy generation with *feed-in tariffs* (commonly used in Europe), which guarantee above-market rates for power. Consistent with the quoted language in Section 210(b), FERC permits states to set different avoided cost rates for different generation technologies, but they cannot exceed actual avoided costs for that technology. 18 C.F.R. §292.304(e).

[23] These targets and definitions of qualified sources vary by state. For up-to-date information about state RPS, *see* N.C. Clean Energy Tech. Ctr. *Database of State Incentives for Renewables & Efficiency*, http://www.dsireusa.org (last visited Sept. 24, 2026).

such as near zero or net-zero carbon emissions by the middle of the 21st century. These include California,[24] Hawaii,[25] New York State,[26] Washington,[27] New Mexico,[28] and Minnesota.[29]

III. Permitting

A. Lead Agency Permits vs. Ancillary Approvals

From the energy project developer's perspective, the permitting process in the regulatory anticommons can look like a gauntlet. We can cut through some of its complexity by distinguishing the primary license required for any particular energy project—the *lead agency approval*—from the other important-but-*ancillary approvals* that the project will need to secure from other agencies. Often, the lead agency is an energy-focused regulator like FERC, the Nuclear Regulatory Commission (NRC), or a state PUC or oil and gas commission. But not always. For example, for offshore wind or oil developments it is the US. Department of the Interior (DOI); for oil developments in some states it is the state environmental agency.

Regardless, the lead agency approval will be only one of several required approvals. Which ancillary approvals a project requires will depend upon the specific characteristics of the project. For example, projects located in or near a coastal zone trigger approvals under the Coastal Zone Management Act (CZMA).[30] Projects that emit air or water pollution trigger approvals under the Clean Air Act (CAA)[31] and Clean Water Act (CWA),[32] respectively; those that impact marine mammals may trigger permit or consultation requirements under the Marine Mammal Protection Act (MMPA), impacts to endangered species or their habitats trigger review under the Endangered Species Act (ESA),[33] and so on.

Some ancillary approvals are triggered only when the project requires federal approval. For example, an environmental impact statement (EIS) is required under the National Environmental Policy Act (NEPA) only for "major *federal* actions significantly affecting the quality of the human environment" (emphasis added).[34] A "federal" action is one directly undertaken *or approved* by the federal government. Some energy projects—including most solar farms, or new oil and gas drilling—do not require federal permits, and so do not trigger NEPA. But if the solar farm or drilling impacts federal wetlands, it may require a permit under CWA Section 404 from the U.S. Army Corps of Engineers (the Corps).[35] The Corps, in turn, would then need to undertake an environmental review under NEPA to determine if

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[24] CAL. PUB. UTIL. CODE §399.11 (2019); CAL. PUB. UTIL. CODE §399.15 (2019); CAL. PUB. UTIL. CODE §399.30 (2019).
[25] HAW. REV. STAT. §269-92.
[26] N.Y. ENV'T. CONSERV. LAW §75-0107 (McKinney).
[27] WASH. REV. CODE ANN. §19.285.040.
[28] Energy Transition Act, S.B. 489, 54th Leg., 1st Sess. (N.M. 2019).
[29] MINN. STAT. §216H.02.
[30] Coastal Zone Management Act of 1972, Pub. L. No. 92-583, 86. Stat. 1280.
[31] *See* 42 U.S.C. §6921.
[32] *See* 42 U.S.C. §7412.
[33] *See* 16 U.S.C. ch. 35.
[34] National Environmental Policy Act of 1969, Pub. L. No. 91-190, 83 Stat. 852.
[35] 33 U.S.C. §1344.

a full EIS is required. Even if an environmental review under NEPA is not required, state environmental review laws may apply to some projects.

Figure 2 summarizes the regulatory environment for some common types of energy projects today.

	Federal	State	Local	Common Ancillary Reviews (Federal)
Nuclear Power Plants	Nuclear Regulatory Comm'n			NEPA, CWA
Fossil-Fueled Power Plants		Public Utility Comm'n (PUC) or other siting agency	Municipalities (in some states)	CAA, CWA
Wind Farms—Onshore		PUC or other siting agency	Municipalities (in some states)	
Offshore Energy Development	U.S. Dep't of the Interior (beyond state waters)	Various state agencies (within state waters)		NEPA, CZMA, ESA, MMPA
Solar Farms		PUC or other siting agency	Municipalities (in some states)	ESA
Transmission Lines		PUC	Municipalities (in some states)	CWA
Oil & Gas Production Facilities—onshore		Oil & Gas Comm'n	Municipalities (in some states)	CAA, CWA
Oil Pipelines		PUC, State Oil & Gas Comm'n, or legislature		CAA, CWA
Natural Gas Pipelines	Federal Energy Regulatory Comm'n			NEPA, CAA, CWA
Liquefied Natural Gas Terminals—Onshore	Federal Energy Regulatory Comm'n			NEPA, CWA, CZMA

Figure 2. Energy project siting authority—lead agency. Shaded cells denote lead agency.

B. Lead Agency Approvals

1. Certificates of Need and "the Public Interest"

For most power plants,[36] transmission lines,[37] natural gas pipelines,[38] and oil pipelines,[39] the lead agency will be either FERC or a state PUC, and the required permit the *certificate of need* (CON, also known as a *certificate of convenience and necessity* or CCN). The CON is another instrument of public utility law designed to protect ratepayers and voters by preventing investments in utility-owned infrastructure that are not needed to meet the IOU's service obligations, or are otherwise not in the *public interest*. It is also a landowner protection requirement, since the power of eminent domain to acquire property for the project flows with the issuance of the CON in most circumstances.[40]

Thus, for almost a century, public utility laws have prohibited issuing a CON unless the project serves the public interest in these ways. The lead agency makes the public interest determination based on an evaluation of the project impacts—economic, environmental, social—within its jurisdiction, and after opportunity for public input. In states with strong climate policies, proposed fossil fuel plants that emit carbon may be deemed contrary to the public interest and denied a CON; whereas those same types of power plants may be deemed in the public interest in places that lack strong climate policies.[41]

Notice in Figure 2 that natural gas pipelines must secure a CON from FERC, while oil pipelines and electric transmission lines must secure a CON from each state through which they pass. This can be difficult, even if the project demonstrates a strong market need and positive net benefits. If one of the states through which the line passes sees the development of the line as contrary to its local interests, it may deny the CON. Imagine, for example, a high-voltage, direct current (HVDC) interstate

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[36] Generally, the lead agency in this case is the state PUC or a state power plant siting agency, such as the California Energy Commission. Most states continue to require a CON for new power plants even in competitive wholesale markets, even though ratepayers will not be forced to cover the new plant's total costs (plus fair return) in those locations. Texas, for example, no longer requires a CON for new power plants within the ERCOT zone. But in many other states with competitive wholesale markets, this vestigial requirement remains in place. As indicated in Figure 2, hydroelectric plants and nuclear power plants secure their lead agency permit from federal agencies: FERC is lead agency for the former, and NRC is lead agency for the latter.

[37] States are the lead agency for siting transmission lines. The Federal Power Act (FPA) did not empower FERC to issue CONs for interstate transmission.

[38] The Natural Gas Act establishes FERC as the lead agency and issuer of the CON for interstate natural gas pipelines. 15 U.S. Code §717f(c). For intrastate natural pipelines (and oil pipelines), it is the state PUC or oil and gas agency.

[39] Colin P. O'Rourke, *Oil Pipeline Regulation: The Current Patchwork Model and an Improved National Solution,* LSU J. ENERGY L. & RES. CURRENTS (Feb. 2, 2016), https://jelr.law.lsu.edu/2016/02/02/oil-pipeline-regulation-the-current-patchwork-model-and-an-improved-national-solution/.

[40] The Natural Gas Act delegates the power of eminent domain to holders of CONs for interstate pipelines. *See* 15 U.S.C. §717f(h). State public utility law grants this same power to holders of CONs for intrastate pipelines, transmission lines, and oil pipelines. Some other lead agency approvals also delegate this power to the licensee. Under the FPA, when FERC grants a hydroelectric license or transmission line construction permit (under it's yet-to-be used backstop siting authority), those approvals also come with the power of eminent domain. *See* 16 U.S. Code §§797 (hydroelectric facilities) and 824p(e) (interstate transmission lines).

[41] For two different normative evaluations of this aspect of traditional public utility law, *see* William Boyd, *Public Utility and the Low Carbon Future*, 61 UCLA L. REV. 1614 (2014), and Joshua C. Macey & Brian Richardson, *The Public Law of Public Utilities*, 42 YALE J. REG. 179 (2025).

transmission line that crosses three states: (1) an upstream state from which inexpensive power from new wind farms will be transmitted to downstream customers at the other end of the line; (2) a pass-through state that will gain neither the jobs associated with the new wind farms nor any of the inexpensive power they will produce; and (3) a downstream state where customers will have access to the inexpensive wind power delivered over the line. In that case, the pass-through state has little to no incentive to grant the project a CON. For that reason, Congress amended the Federal Power Act (FPA) in 2005 and 2021 to provide FERC with backstop transmission siting authority that may be exercised when states refuse to develop needed transmission.[42] FERC has not yet used this power. However, at least one federal court of appeals has held that a state's refusal to permit new interstate transmission in competitive wholesale markets is preempted under the Supremacy Clause.[43]

The widening partisan gap on climate and energy policy can also make it difficult to secure a CON from each state through which a multistate line must pass. If one of the states through which the pipeline passes sees the development of fossil fuel infrastructure as contrary to its interests, it may deny the CON. And the mirror image obstacle could confront a new interstate transmission line designed to promote renewable energy development. Note, however, that these coordination problems and this risk of a "single state veto" for linear infrastructure projects is limited to transmission and oil pipelines, not natural gas pipelines. Congress designated FERC as the lead agency for interstate natural gas pipelines, and its public interest determinations focus on the entire project. Given that the Natural Gas Act of 1938 was closely modeled after the FPA of 1935 (with many identical provisions), one might ask why Congress did not designate a federal CON regime for interstate transmission. The presumptive answer is that in the 1930s, it foresaw the need to transport natural gas long distances from production areas to demand centers; it did not foresee the need to build power plants in windy and sunny places far from demand centers.

2. Other Lead Agency Permits

As Figure 2 indicates, for certain types of energy projects, the lead agency approval is not the CON, but rather a bespoke approval created just for that type of project. Nevertheless, many of these approvals involve standards that are similar to the public interest analyses associated with securing a CON.

Hydroelectric projects must secure a license from FERC. FERC must conclude that the project it licenses is "best adapted to a comprehensive plan for developing the waterway"; but in making that determination, it will balance a number of statutory criteria, including economic need, environmental impacts, impacts to locals, etc. Nuclear power plants must secure a license from NRC, and NRC's decision criteria are focused on safety, including environmental safety, as well as national security.[44] For offshore energy (usually oil and gas production or wind farms) in federal waters, the lead agency

[42] Those backstop siting provisions can be found at 16 U.S.C. §824p.

[43] *See* Transource Pennsylvania v. Defrank, 156 F.4th 351, (3d Cir. 2025). Some states have tried to protect incumbent utilities' exclusive right to build new transmission by granting in-state IOUs a right of first refusal to build new transmission. The U.S. Court of Appeals for the Fifth Circuit struck down one such law as a violation of the dormant Commerce Clause. NextEra Energy Cap. Holdings, Inc. v. Lake, 48 F.4th 306 (5th Cir. 2022), *cert. denied*, 144 S. Ct. 485 (2023).

[44] *See* 10 C.F.R. §52.81 (setting out NRC's standards for reviewing an application for a nuclear power plant).

is DOI's Marine Minerals Administration (MMA) (formerly the Bureau of Ocean Energy Management (BOEM)). MMA's permitting jurisdiction over offshore energy development comes from the Outer Continental Shelf Lands Act (OCSLA),[45] which requires separate approvals for each stage of the project from leasing to project operation; those approvals, in turn, balance project needs against a variety of environmental, safety, and navigation impacts.

When it comes to fossil fuel production, the lead agency approvals for new projects look a little different. The basic approval required for new oil and gas wells comes from state agencies, usually PUCs or oil and gas commissions. In most oil and gas-producing states, the rules allow production to go forward as long as the developer complies with a long list of requirements related to property rights, drilling procedures, well construction, wastewater management, and more. For new liquefied natural gas (LNG) production, Section 7 of the Natural Gas Act designates FERC as the lead agency and empowers the agency to grant permits it deems "necessary and appropriate" and otherwise consistent with the public interest.[46] That section also prohibits FERC from denying a permit for certain specified reasons,[47] and specifies that the export of LNG to nations with which the United States has a free trade agreement is in the public interest.[48] FERC regulations make clear that the agency will examine the environmental and safety impacts of the project before issuing the necessary permit.[49]

And finally, under the Surface Mining Claims and Reclamation Act of 1977 (SMCRA),[50] prospective developers of new coal mines must secure a permit from DOI's Office of Surface Mining (OSM), or a state agency to which OSM has delegated permitting authority. SMCRA establishes a relatively onerous set of requirements for new coal mines, the most important of which relate to reclamation of the land after completion of mining activities. The applicant must submit an acceptable reclamation plan in advance of permitting, and must provide adequate financial assurance (e.g., a bond or insurance) to guarantee that the reclamation plan can be completed.

C. Ancillary Approvals

The menu of ancillary approvals potentially triggered by energy projects is too numerous and varied to describe comprehensively here. Instead, we will focus here on some of the more significant and common ones.

1. The Clean Air Act

For new fossil-fueled power plants, securing the right to emit pollutants regulated by the CAA is sometimes as big a hurdle as securing the CON from the state PUC or other power plant licensing board. Energy projects that emit enough of a regulated air pollutant will require a permit from the state environmental agency under the CAA. The applicable emissions requirements will depend upon where the project is located, the particular pollutants involved, and on other project characteristics.

[45] 43 U.S.C. §§1331-1356c.
[46] 15 U.S.C. §717b.
[47] 15 U.S.C. §717b(e)(3)(b).
[48] 15 U.S.C. §717b(a).
[49] 18 C.F.R. Part 153, especially §153.8(a)(8).
[50] 30 U.S.C. ch. 25.

Generally speaking, the Act regulates emissions of toxic pollutants (like mercury) more stringently than conventional pollutants (like sulfur dioxide), and emissions in places with more existing pollution more stringently than emissions in places with less pollution.[51]

Following the U.S. Supreme Court's decision in *Massachusetts v. EPA* (2007) and EPA's subsequent "endangerment finding" that concluded GHGs endanger the public health and welfare, EPA has also issued regulations for those pollutants under the CAA. However, the second Trump Administration has proposed both rescinding the endangerment finding and eliminating those regulations. Whether and the extent to which the CAA authorizes EPA to regulate GHGs that contribute to climate change is in flux and the subject of ongoing litigation.

2. Endangered Species

Section 9 of the ESA prohibits any person from harming any federally listed endangered species,[52] and Section 7 prohibits the federal government from "jeopardiz[ing] the continued existence" of any such species[53]—including through the issuance of permits to construct an energy project. The Act's definition of "harm" includes damaging the species' critical habitat. Therefore, when a developer seeks a federal permit to build a power plant, transmission line, pipeline, or other energy project in or near the habitat of an endangered species, the permitting agency must request a *biological opinion* from the federal agency charged with protecting the species—either the U.S. Fish and Wildlife Service or the National Marine Fisheries Service (NMFS)—affirming that the Section 7 prohibition will not be violated.[54]

3. Impacts to Waterways

Many energy projects trigger one or more required permissions under the CWA. Thermal power plants, refineries, and LNG facilities typically require a discharge permit under CWA Section 402, usually administered by the applicable state environmental agency.[55] And CWA Section 401 prohibits a federal agency from issuing a permit for any project that may result in a discharge the project has secured a certificate from the applicable state that the project will comply with the water quality protection provisions of the Act.[56] Projects with a large geographic footprint—such as solar farms, wind farms, and linear infrastructure like transmission lines and pipelines—may trigger the need for a wetlands permit under Section 404 of the statute if the project may alter (add fill material to) federal

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[51] *See* RICHARD K. LATTANZIO, CONG. RSCH. SERV., RL30853, CLEAN AIR ACT: A SUMMARY OF THE ACT AND ITS MAJOR REQUIREMENTS (updated Sept. 13, 2022).
[52] Section 9 actually prohibits "taking" an endangered species, where "taking" includes harming the species. 16 U.S.C. §§1538(a)(1)(B) and 1532(19).
[53] 16 U.S.C. §1536(a)(2).
[54] 16 U.S.C. §1536(b).
[55] Section 402 prohibits discharges of pollutants without a permit. 33 U.S.C. §1342. The term "discharge" is defined as the addition of pollutant from a point source to navigable waters. 33 U.S.C. §1362(7) and (16). The heat added to power plant cooling water is a pollutant under the statute. And the term "navigable waters" excludes entirely intrastate waters. *See* City & Cnty. of San Francisco v. EPA, 604 U.S. 334 (2025).
[56] 33 U.S.C. §1341.

wetlands.[57] That permit is issued by the Corps,[58] which is also the agency responsible for regulating project work in waterways that may affect navigation under the Rivers and Harbors Act of 1899.[59]

Box 2. Vineyard Wind: A Case Study

Consider the Vineyard Wind Project, a large wind farm located in federal waters in the North Atlantic. This project had two lead agencies: BOEM managed the offshore siting process, and the Massachusetts Energy Facilities Siting Board (EFSB) managed the Massachusetts-specific impacts of the project. Because Massachusetts has its own NEPA analogue, the ESFB managed the EIS and general environmental review. BOEM granted the OCSLA-required approvals at each stage of project development.[60] The project also secured various ancillary approvals governing (among other things):

- Impacts to commercial fisheries from the NMFS
- Impacts to endangered marine species from the NMFS
- Impacts to navigation from the Corps
- Impacts to air travel from the Federal Aviation Administration
- State and local approvals associated with bringing project power to shore and introducing it into the New England power grid[61]

These are just a sampling of the various ancillary approvals secured by Vineyard Wind; and the project sponsor created an online "permitting dashboard" that tracked the project's progress over the 3 years and 7 months it took to secure all the necessary permits.[62]

D. Ancillary Approvals and Jurisdictional Conflicts

Because the permitting environment is so complex (see, for example, Box 2), lead agencies sometimes help project sponsors coordinate the management of ancillary approvals. Federal agencies will solicit the input of other federal agencies, and may establish rules or guidance for applicants regarding common ancillary approvals. And in some cases, well-established interagency coordination procedures or systems of cooperative federalism define (more or less clearly) the jurisdictional boundaries between

[57] 33 U.S.C. §1344.
[58] *See* 33 C.F.R. Parts 320 and 325.
[59] 33 U.S.C. §403.
[60] *See* 30 C.F.R. Part 585.
[61] *See* Noah Asimov, *Edgartown, Vineyard Wind Settle Cable Dispute*, VINEYARD GAZETTE (Oct. 1, 2019), https://vineyardgazette.com/news/2019/10/01/edgartown-vineyard-wind-settle-cable-dispute.
[62] Permitting Dashboard, *Vineyard Wind* (last visited Sept. 24, 2026), https://www.permits.performance.gov/permitting-project/other-projects/vineyard-wind. Although the dashboard indicates that the permitting process was completed in July 2021, the project did not send electricity to the grid until January 2024.

agencies. For example, there are memoranda of understanding (MOU) between EPA and the Corps to manage their shared jurisdiction over wetlands permitting.[63] And as noted in Part I of this module, sometimes federal permitting preempts state jurisdiction, or state requirements preempt local jurisdiction.[64]

But even if a federal regime purports to preempt sizable swaths of state and local regulatory authority, state and local veto gates may nevertheless offer local opponents powerful leverage. Consider the licensing regimes for hydroelectric power projects and nuclear power projects. Both are governed by federal statutes: the FPA[65] and Atomic Energy Act,[66] respectively. Both establish a federal lead agency: FERC for hydro projects and NRC for nuclear power plants. Both enabling statutes preempt broad swaths of state regulatory authority, seemingly easing the path to project completion.[67] But neither federal statute preempts *all* state and local regulatory authority.[68] In addition, states, local governments, nongovernmental organizations, and others are guaranteed formal rights to participate in the agency licensing proceeding; and in practice, lead agencies are often reluctant to dismiss or overrule state and local government concerns.[69]

Furthermore, some federal statutes authorize *state agencies* to exercise *federal power*. For example, Section 401 of the CWA[70] requires host states to certify that federally licensed energy projects will not endanger water quality. In recent years, the state of New York has used that provision to veto new natural gas pipelines that would deliver gas to New England,[71] where the electricity sector must rely on relatively dirty diesel generators and more expensive, imported LNG during winter cold snaps.[72] And the CZMA

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[63] U.S. Environmental Protection Agency, *Memorandum of Agreement Regarding Mitigation Under CWA Section 404(b)(1) Guidelines* (Feb. 6, 1990), https://www.epa.gov/sites/default/files/2019-05/documents/1990_army-epa_mitigation_moa.pdf; Fed. Energy Regul. Comm'n, *Memorandum of Understanding Between the Federal Energy Regulatory Commission (FERC) and the Commodity Futures Trading Commission (CFTC) Regarding Information Sharing and Treatment of Proprietary Trading and Other Information* (Oct. 12, 2005), https://www.cftc.gov/sites/default/files/files/opa/opacftcfercmou.pdf.

[64] For a discussion of federal preemption and state preemption regimes in energy law, *see* David B. Spence, *Federalism, Regulatory Lags and the Political Economy of Energy Production*, 161 U. PENN. L. REV. 431, 468-77 (2013) (summarizing federal preemption regimes for energy production facilities); and David B. Spence, *The Political Economy of Local Vetoes*, 93 TEX. L. REV. 351 (2014) (focusing on state preemption of local regulation).

[65] Federal Power Act of 1935, Pub. L. No. 116-158, 49 Stat. 847.

[66] Atomic Energy Act of 1954, Pub. L. No. 83-703, 68 Stat. 919.

[67] *See* First Iowa Hydro-Elec. Coop. v. Federal Power Comm'n, 328 U.S. 152 (1946) (the FPA preempts state siting authority over hydro projects); California v. Fed. Energy Regul. Comm'n, 495 U.S. 490 (1990) (affirming the *First Iowa* holding); and Pac. Gas & Elec. Co. v. State Energy Res. Conserv'n & Dev. Comm'n, 461 U.S. 190 (1983) (the Atomic Energy Act preempts state regulation of nuclear safety).

[68] The FPA does not preempt state water rights. *See* 16 U.S.C. §821 (expressing the congressional purpose to leave state laws governing water rights undisturbed by the Act). The Atomic Energy Act does not prohibit state regulation of certain environmental (as opposed to safety) aspects of nuclear power. *Pac. Gas & Elec. Co.*, 461 U.S. 190, 191, 213-16 (upholding a California statute regulating nuclear waste storage because the statute had an "economic rather than safety purpose").

[69] David B. Spence, *Managing Delegation Ex Ante: Using Law to Steer Administrative Agencies*, 28 J. OF LEGAL STUDIES 413 (1999).

[70] 33 U.S.C. §1341.

[71] *See* Alexandra B. Klass & Jim Rossi, *Reconstituting the Federalism Battle in Energy Transportation*, 41 HARV. ENV'T L. REV. 423, 425-26 (2017).

[72] *See id.* at 427; *see also* Steve Everly, *Why Natural Gas From Putin's Russia Has to Be Imported to New England*, WASH. EXAM'R (Mar. 24, 2018), https://www.washingtonexaminer.com/opinion/op-eds/why-natural-gas-from-putins-russia-has-to-be-

gives states a qualified veto over offshore developments that conflict with their plans for their coastal zones.[73] These kinds of state-exercised federal powers are never preempted by the lead agency's enabling legislation. Congress designed them as brakes on project development whose forward momentum is economic, and to steer private capital toward the provision of *cleaner*, *safer* energy. But they provide leverage to opponents of clean and dirty energy infrastructure alike, and slow development of new energy infrastructure.

IV. Public Participation

A. Models of Public Participation

Perhaps the best-known model of public participation in regulatory agency decision processes is the federal Administrative Procedure Act[74] (APA), which requires (and specifies minimum basic procedures for) the provision of *opportunities* for public participation in both agency rulemaking (broad policymaking) and agency adjudication (party-specific decisions including permitting). The APA requires that agencies publish their intention to take rulemaking or adjudicatory action before they take it, and to inform interested parties when, where, and how they may introduce facts, evidence, or arguments into the decision record.[75]

Some federal permitting regimes call for additional consultation with affected groups. For example, FERC's hydroelectric licensing regulations require prospective applicants for a license to consult with a list of specified government agencies *before* filing the application for a project license,[76] after which FERC must comply with APA and NEPA participation requirements during its consideration of the application.

The rights to participate in state and local regulatory decision processes are more varied. Many states have adopted the 1982 Model State Administrative Procedure Act,[77] which mirrors its federal counterpart in many ways. Most state permitting regimes include some form of notice and right to be heard; and most regulatory agencies—federal, state, and local—are subject to open meetings and freedom of information laws designed to make their deliberations more transparent.[78] In these ways, the law attempts to ensure that the final record of decision reflects all the considerations, perspectives, and evidence relevant to the decisionmaker's statutory charge.

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imported-to-new-england; Naureen S. Malik, *Cold Snap Makes New England the World's Priciest Gas Market*, BOS. GLOBE (Dec. 27, 2017), https://www.bostonglobe.com/metro/2017/12/27/cold-snap-makes-new-england-world-priciest-gas-market/ILRzKrRTCtW4uNYRZeEIvK/story.html.

[73] 16 U.S.C. §1456(c).

[74] 5 U.S.C. §§551-559.

[75] 5 U.S.C. §§553(b)-(d) (rulemakings) and 554(c) (adjudications).

[76] 18 C.F.R. §4.38.

[77] For a summary, *see* Anne K. Pecora, *The Model State Administrative Procedure Act: Planned Restraint on the Consolidation of Power by Executive Branches of State Governments*, 32 VILL. L. REV. 451 (1987).

[78] For a compendium of state laws, *see* CAPLAW, *Open Meetings Laws—a State-by-State Guide* (last visited Sept. 24, 2026), https://caplaw.org/resource-collections/open-meetings-law-state-by-state-guide.

B. Maintaining the Social License to Operate

To project developers, navigating the complex system of veto gates described in Part III can seem time-consuming, expensive, and daunting—both legally and politically. The politics of siting are inherently difficult because the benefits of new energy infrastructure—greater energy security and affordability, as well as the environmental benefits of clean energy—tend to flow mostly to people far from the project location; by contrast, the costs—pollution, land use changes, aesthetic impacts, traffic, and other impacts—tend to be localized. Therefore, local opposition to energy projects is often logical, and the more power a licensing regime devolves to state and local governments, the more difficult it is for the project to navigate regulatory hurdles successfully. State and local government opposition accounts for the spread of local restrictions on energy project developments over the last few decades.[79]

Energy project developers have responded to this challenge by embracing the use of so-called community benefit agreements (CBAs). CBAs are agreements between developers and local governments or local groups in which the developer agrees to provide specified (pecuniary or non-pecuniary) benefits to locals. The developer may commit to share project revenues with locals, to employ a specified percentage of locals, to take actions to mitigate project impacts (beyond those required by law). In return, the local party to the agreement typically agrees either to cooperate in the development of, or at least not to oppose, the project. In some cases, the local party may become a local advocate for the project. Of course, the existence of a CBA does not prohibit local non-parties to the agreement from opposing the project, in court or otherwise.[80]

C. Facilitating Representation of Underrepresented Groups

It is well established that the ability of "not in my backyard" or "NIMBY" groups to effectively oppose new energy projects is correlated with wealth, race, and political sophistication. Those on the lower end of the socioeconomic ladder tend to have less time and fewer financial resources to devote to participation in permitting proceedings, or to litigation challenging the issuance of a permit. This can produce public decisions that are less attentive to their interests than to those of wealthier, more politically sophisticated citizens.[81] The environmental justice and energy justice movements are concerned with understanding and remedying this problem. But the willingness of policymakers to address it has recently become embroiled in partisan politics.

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[79] *See* Robi Nelson et al., *Survey of Utility-Scale Wind and Solar Developers Report, Lawrence Berkeley National Laboratory* (Jan. 2024), https://emp.lbl.gov/publications/survey-utility-scale-wind-and-solar; Lawrence Suskind et al., *Sources of Opposition to Renewable Energy Projects in the United States*, 165 ENERGY POL'Y 112922 (2022).

[80] For a summary of the origins of CBAs generally, *see* Vicki Been, *Community Benefit Agreements: A New Local Government Tool or Another Variation on the Exactions Theme?*, 77 U. CHI. L. REV. 5 (2010). For a discussion of their use in the context of energy projects, *see* Sandy Kerr et al., *Understanding Community Benefit Payments From Renewable Energy Development,* 105 ENERGY POL'Y 202 (2017); and Ruby Moore-Bloom, Community Benefits Agreements: Opportunities, Barriers, and Best Practices, Clean Energy Transition Institute (July, 24 2025), https://www.cleanenergytransition.org/post/community-benefits-agreements-opportunities-barriers-and-best-practices.

[81] James T. Hamilton, *Politics and Social Costs—Estimating the Impact of Collective Action on Hazardous Waste Facilities*, 24(1) RAND J. ECON. 101 (1993).

In 1994, President Bill Clinton signed an executive order (EO) requiring consideration of impacts to disadvantaged populations in federal regulatory decision processes.[82] The George W. Bush, Barack Obama, and Joseph Biden Administrations each attempted to implement that order in their regulatory review processes. The Biden Administration took additional actions to afford underrepresented populations more opportunities to participate in regulatory policymaking and regulatory decisions through its "Justice40" initiative. However, the second Donald Trump Administration rescinded the Clinton EO in 2025, and eliminated most of the Biden Administration's programs aimed at enhancing public participation by underrepresented groups.[83] In the states, there is a wide variety in the degree to which state governments embrace public participation for underrepresented groups in energy regulatory decisionmaking. Some states emulate the Biden Administration's focus on energy and environmental justice; others emulate the Trump Administration's opposition to those ideas.[84]

V. Project Operation and Ongoing Compliance

Financing and permitting, along with public input during the process, present multiple decision points in project development, many of which create opportunities for legal challenge. The legal implications for owners and operators do not end there, however, and continue after an energy facility has obtained all the necessary federal, state, and local approvals to start construction and begin operation. The applicability of different legal regimes varies greatly depending on the project type, size, and location, among other factors.

However, by way of example, once a project is operational, there may still be ongoing environmental compliance requirements. This includes ensuring operations do not exceed the permitted emissions limits for various air pollutants, like mercury and sulfur dioxide; or that operations do not impact various resources, including wildlife, in unanticipated ways; or that any discharges into regulated waters remain within the bounds of permitted activity. It might also mean navigating a complex and shifting tax code as the scope and scale of the energy credits landscape has changed significantly in recent years.

VI. Decommissioning

Ideally, when energy infrastructure comes to the end of its useful life, it should be properly decommissioned to ensure that whatever is left behind is safe and consistent with the surrounding land uses. If the facility is not properly decommissioned, either because it is not required or because the project owner fails to follow the requirements, it can leave others with a mess to clean up. States with a long history of oil production, like Texas and Pennsylvania, have hundreds of thousands of unplugged, abandoned wells between them. Improperly closed coal mines show up on lists of

[82] Exec. Order No. 12898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations (Feb. 11, 1994).
[83] Exec. Order No. 14173, Ending Illegal Discrimination and Restoring Merit-Based Opportunity (Jan. 21, 2025).
[84] For a summary of state positions on this issue, *see Environmental Justice, State by State*, VERMONT LAW & GRADUATE SCHOOL (last visited Sept. 24, 2026), https://ejstatebystate.org/.

contaminated sites that others must pay to remediate. And farmers worry about the abandonment of solar panels on their land at the end of a project's useful life. Decommissioning rules, where they exist, are intended to address these problems.

Though the rules differ by project type, all *federal* permitting regimes for energy production provide for decommissioning those facilities at the end of their useful lives, and require the owner to provide some form of financial assurance that decommissioning will be performed consistent with regulatory standards. This is true for hydroelectric projects licensed by FERC,[85] coal mines authorized by OSM or its state delegates, nuclear power plants licensed by NRC,[86] and offshore wind or fossil fuel projects licensed by MMA. For nuclear and hydroelectric facilities, the licensee must contribute to a decommissioning fund over the life of the project.[87] For offshore oil developments and offshore wind, the applicant must post sufficient financial assurance to cover decommissioning at the permitting stage.[88] For coal mines, OSM Reclamation and Enforcement requires both up-front and continuing contributions to assure that reclamation plans can be completed.[89]

When it comes to state-permitted energy infrastructure like onshore wind and solar farms, oil and gas wells, and fossil-fueled power plants, decommissioning rules vary greatly by state.[90] Some states have established decommissioning rules for state-licensed power plants that are analogous to the federal rules described above.[91] Some states authorize local governments to establish the rules, particularly for renewables projects.[92] In the absence of formal rules, state PUCs can use their ratemaking leverage over IOUs to ensure that IOU-owned power plants will be properly decommissioned. But in competitive wholesale power markets where many renewable and fossil-fueled power plants are not owned by IOUs, states without formal decommissioning requirements must rely on plant owners' goodwill (or desire to avoid cleanup litigation) to ensure proper decommissioning. For coal-fired power plants with onsite coal ash disposal facilities, there is federal help in the event state law is lacking. Coal ash landfills and ponds are regulated as solid waste disposal facilities under the federal Resource Conservation and Recovery Act (RCRA),[93] which mandates decommissioning (including the provision of financial assurance by plant owners).[94]

However, the presence of decommissioning rules on the books is not necessarily sufficient to ensure proper decommissioning. Sometimes, financial assurance requirements fall short of the actual cost of

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[85] 18 C.F.R. Part 6.
[86] 10 C.F.R. §50.82.
[87] 18 C.F.R. §16.11 (hydro facilities); 10 C.F.R. §72.30 (nuclear power plants).
[88] 30 C.F.R. Part 250, subpart Q (oil); 30 C.F.R. Part 585 (wind).
[89] 30 C.F.R. §80.11 (reclamation bond); §870.15 (reclamation fee).
[90] DANIEL RAIMI, DECOMMISSIONING U.S. POWER PLANTS: DECISIONS, COSTS AND KEY ISSUES, RESOURCES FOR THE FUTURE (2017), https://www.rff.org/publications/reports/decommissioning-us-power-plants-decisions-costs-and-key-issues/ (summarizing the decommissioning challenge for renewable and fossil-fueled power plants).
[91] *See* RAIMI, DECOMMISSIONING U.S. POWER PLANTS.
[92] *See* TAYLOR L. CURTIS ET AL., A SURVEY OF FEDERAL AND STATE-LEVEL SOLAR SYSTEM DECOMMISSIONING POLICIES IN THE UNITED STATES, NAT'L RENEWABLE EN. LAB., NREL/TP-6A20-79650 (2021), https://docs.nlr.gov/docs/fy22osti/79650.pdf.
[93] 42 U.S.C. §§6901 et seq.
[94] 40 C.F.R. Part 257, subpart D.

decommissioning, as has sometimes been the case in nuclear plant decommissioning[95] and coal mine reclamation.[96] Sometimes, energy assets change hands over their lifetimes, passing to less-solvent companies, further jeopardizing the integrity of the decommissioning process. For example, even though most oil and gas-producing states have rules for closing and plugging wells that are no longer in production, their financial assurance requirements tend to be weak; producers can go bankrupt, which is how Texas and Pennsylvania ended up with some of their hundreds of thousands of abandoned, unplugged wells.

VII. Conclusion

Regardless of the energy source, whether a natural gas plant, nuclear power plant, a wind farm, or an array of solar panels, making energy requires building facilities and associated infrastructure. Although the legal framework that governs each source can vary, they tend to share many generic project development principles: common financing, permitting, public involvement, operational compliance, and decommissioning challenges. Legal disputes can arise at each step along the way, and it is common for the social, economic, environmental, and legal dimensions of these projects to be at issue in litigation.

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[95] *See, e.g.*, Christina Simeone, *Nuclear Decommissioning: Paying More for Greater, Uncompensated Risks*, KLEINMAN CTR. FOR ENERGY 10 (2020), https://kleinmanenergy.upenn.edu/wp-content/uploads/2020/08/Nuclear-Decommissioning-Paying-More-for-Greater-Uncompensated-Risks-1.pdf.

[96] *See* U.S. GOV'T ACCOUNTABILITY OFF., FINANCIAL ASSURANCES FOR RECLAMATION: FEDERAL REGULATIONS AND POLICIES FOR SELECTED MINING AND ENERGY DEVELOPMENT ACTIVITIES (Dec. 16, 2016), https://www.gao.gov/assets/gao-17-207r.pdf.