GAP ANALYSIS OF PERMITTING REFORMS IN CALIFORNIA, ILLINOIS, NEW YORK, AND WASHINGTON

APRIL 1, 2026

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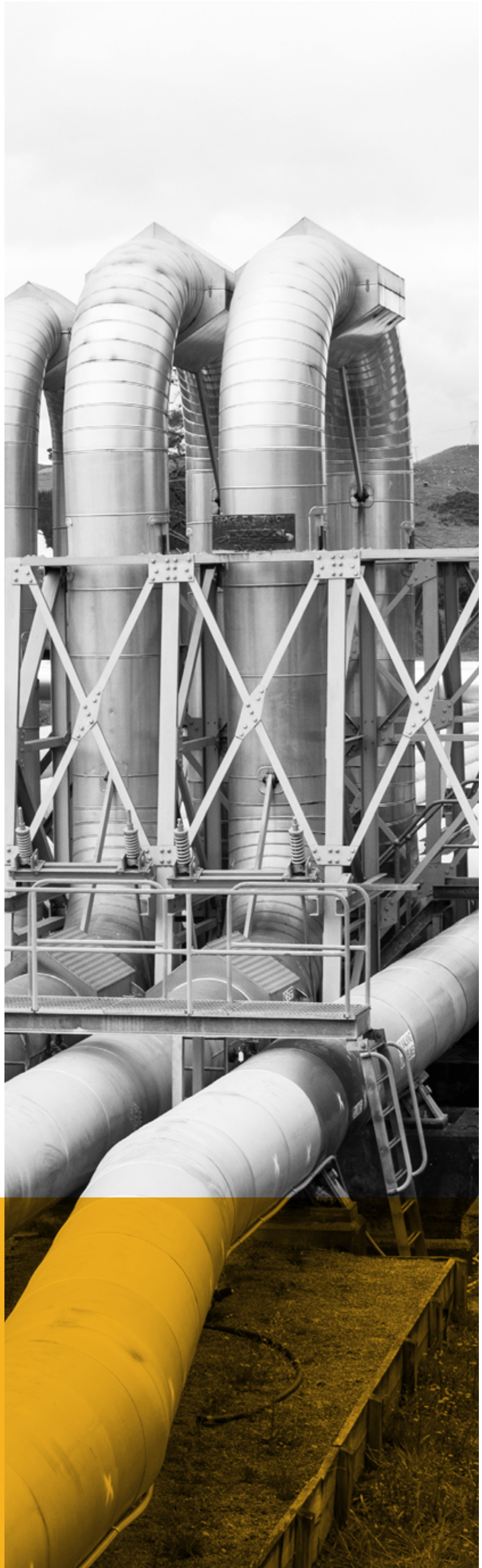

EXECUTIVE SUMMARY

The United States needs to build far more generation, storage, and transmission facilities—and build them much faster—if it is going to meet its reliability, affordability, and energy policy goals. Among the most significant barriers to rapid development of new energy infrastructure are outdated siting and permitting processes. Although recent federal reforms have sought to accelerate project review and additional federal reforms are urgently needed, federal action alone is unlikely to produce the scale of change required. Because generation, storage, and transmission projects remain heavily shaped by state and local authorities, reforms to state and local siting and permitting processes are central to ensuring energy infrastructure is constructed on time.

In many states, debates around siting and permitting reform began with the question of whether state policy should play a stronger role in facilitating renewable energy siting. However, the debates have evolved into a second-generation question: how to design reforms that perform in practice. This report presents a targeted gap analysis of recent renewable energy siting and permitting reforms adopted in California, Illinois, New York, and Washington. Drawing on statutory and regulatory review, permitting records, and early implementation outcomes, the report treats permitting reform as process architecture—evaluating how systems surface determinative issues, discipline scope, and close decisions in ways that withstand legal and commercial risk.

The central finding is that each state reform has produced meaningful gains, but not a complete solution. All four states have attempted to improve some aspects of the siting process, and projects that previously would have faced greater local obstruction are now more likely to move forward. However, common lessons emerge from where those reforms still fell short:

First, procedural reforms alone do not ensure that projects are built on time. Delay often shifts rather than disappears when reforms relocate uncertainty instead of resolving it. In deadline-driven reforms, the point at which an application is deemed complete has become one of the most consequential decisions in the entire process. Post-approval obligations similarly have created a second permitting timeline for major plans, studies, or other agency approvals.

Second, local restrictions remain a major obstacle even where states have enacted reforms. In nearly every state examined, local governments continue to use zoning, land-use controls, and procedural hurdles to restrict or effectively block clean energy and storage development. State preemption has been an important tool, but preemption alone does not eliminate delay, cancellation risk, or litigation. Many communities feel excluded from decisions that directly affect them, and local officials distrust assurances from developers or regulatory agencies that impacts will be fairly managed. Opposition therefore reappears through lawsuits, political pressure, and procedural tactics, underscoring that reassigning authority is only one part of a workable reform strategy.

Third, persistent public opposition cannot be understood simply as "NIMBY" resistance. Local opposition often arises not only from project-specific concerns, but also from underlying socioeconomic issues and broader disputes over procedural fairness, local autonomy, and the distribution of costs and benefits.

Fourth, modest concessions and procedural engagement alone are no longer sufficient to resolve public opposition consistently. Requirements for "meaningful" engagement are frequently vague and often inadequate in practice. Host-community benefits can mitigate some local impacts, but they are not a substitute for inclusive planning or credible community engagement.

Most fundamentally, generation siting and permitting cannot be understood in isolation from interconnection and transmission planning. In practice, available deliverability often determines where projects can realistically be proposed, which means that many siting conflicts reflect a deeper structural mismatch rather than simply poor site selection. State reforms can make siting and permitting more predictable and efficient, but they cannot by themselves solve a system in which transmission is expanded too reactively and developers must justify major upgrades on a project-by-project basis. Durable deployment therefore depends on much better integration of siting, interconnection, and transmission planning.

Among the four states studied, New York provides the clearest example of a centralized model producing measurable results. Illinois shows that a hybrid system can generate meaningful gains, though with less clarity and consistency. California and Washington illustrate how quickly performance gaps emerge when finality, sequencing, and accountability remain unresolved. The comparison suggests that predictable permitting depends less on any single institutional model than on disciplined process design: surfacing consequential issues early, stabilizing scope before schedules harden, integrating the approvals that determine viability, and confining adjudication to disputes that can alter outcomes. Where those conditions are missing, time reappears as delay, drift, or post-decision limbo, and statutory ambition outpaces implementation.

The recommendations in this report are directed not toward weakening environmental protections or limiting public participation, but toward building permitting processes that resolve the right issues at the right time—producing a more predictable, durable, and legitimate system that can move projects from proposal to operation on timelines consistent with a state's affordability, reliability, and energy policy goals.

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The research for and publication of this report were supported by Arnold Ventures. The author gratefully acknowledges the many individuals who generously contributed their time and insights through interviews. In accordance with privacy and confidentiality protocols, their identities have been anonymized. Their willingness to share their expertise and experience is deeply appreciated.

1 INTRODUCTION

The United States is undergoing a major energy transformation. The interconnection queue, which is full of energy generation and storage projects seeking to join the wholesale electric grid, has grown from under 500 gigawatts (GW) in 2010 to more than 2,300 GW of generation and storage by the end of 2024, far above the roughly 1,200 GW installed on the U.S. grid. However, fewer than one in five queued projects reaches commercial operation, and average interconnection timelines have lengthened from about two years to more than five. At the same time, electricity demand is rising, driven by data centers, industrial reshoring, and electrification, while aging and uneconomic generating units continue to retire. The combination of rising demand, retiring generating capacity, and delayed new supply has created a growing challenge for resource adequacy and affordability.[1]

Delays in bringing new generation and storage online are multifaceted. Limited transmission capacity, high and highly variable network upgrade costs, and protracted study timelines slow the interconnection process. Even after completing interconnection studies, projects

1 U.S. Department of Energy, "Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035" (Apr. 2024); Lawrence Berkeley National Laboratory (hereafter LBNL), "Queued Up: 2025 Edition" (Apr. 2025).

face additional hurdles, including permitting delays, equipment shortages, long lead times, and supply-chain disruptions. Investor confidence has also been shaken by shifting federal and regional conditions, including high interest rates, tariffs, changing tax credit rules and timelines, and evolving capacity accreditation standards. These pressures have contributed to fewer off-take agreements and deferred commercial operation dates.[2] When cost-effective new capacity is delayed, reserve margins tighten, capacity and energy prices rise, and customers pay more than necessary for electricity.[3]

These compounding pressures collide with siting and permitting frameworks that are poorly matched to the scale, pace, and geographic concentration of energy deployment required over the next decade. Estimates suggest the country may need over 60 GW of new renewable power annually for the next decade, requiring on the order of 10 million acres of land—the vast majority rural.[4] Local governments, on the front lines, have increasingly used land-use controls as de facto veto points in response to community concerns about the construction and operation of energy facilities.[5] In many states, local governments have adopted stringent zoning requirements, land-use restrictions, and procedural hurdles that effectively block or severely constrain solar, wind, and battery energy storage projects. Local variation accordingly has become a major determinant of project viability even where statewide policy, market demand, and system need all favor development.[6]

Because local restrictions and organized opposition are now a significant source of project delay, redesign, and cancellation, understanding why those restrictions arise is as important as documenting their occurrences.[7] Public conflict over energy siting is often shaped by disputes about perceived risk, fairness, trust, governance, place attachment, and the strategic use of credible information and counter-expertise. Local officials face a difficult balancing act: recognizing the economic benefits of new infrastructure while responding to the genuine concerns of constituents. Vocal and organized opposition groups can pressure officials to adopt restrictive rules that prioritize local resistance over broader energy objectives.[8] The policy challenge, then, is whether institutions can allocate land use in ways that are fair, predictable, and timely enough to meet reliability and affordability goals while maintaining community trust.[9]

Against this backdrop, California, Illinois, New York, and Washington have pursued distinct siting and permitting reform strategies, each shaped by different legal traditions, political coalitions, and administrative starting points.[10] These reforms range from more centralized state-level siting systems to hybrid or backstop models that preserve a larger local role while

2 American Clean Power Association (ACP), "Federal Chaos Sparks Warning Signs for Clean Energy Investment, According to Q2 Data" (Sept. 16, 2025).

3 Grid Strategies, LLC, "Interconnection Queue Rationing Reforms" (Nov. 2025).

4 Deloitte Research Center for Energy & Industrials, "2025 Renewable Energy Industry Outlook: Renewables Race to Fill Resource Gap as Demand for Clean Energy Is Outpacing Supply" (Dec. 2024); Deloitte Research Center for Energy & Industrials, "2026 Renewable Energy Industry Outlook: Renewables Recalibrate for Resilience Amid Policy Shifts" (Oct. 2025); Boston Consulting Group, "The State of Play in U.S. Energy and Ensuring Future Energy Leadership" (May 2025).

5 Suhail Bhat, et al., "Takeaways from USA TODAY's Investigation of Clean-Energy Opposition," *USA Today (Feb. 21, 2026).*

6 Federico Holm, "The Pathway to a Just Transition Grows Steeper" (Feb. 2026).

7 David J. Hess, "Local Opposition to Renewable Energy: Integrating Misinformation and Controversy Perspectives" (Feb. 2026).

8 Miranda Green, et al., "An Activist Group Is Spreading Misinformation to Stop Solar Projects in Rural America," *NPR (Feb. 2023).*

9 LBNL, "Laws in Order"; Hess, David J., "Local Opposition to Renewable Energy: Integrating Misinformation and Controversy Perspectives" (May 2025).

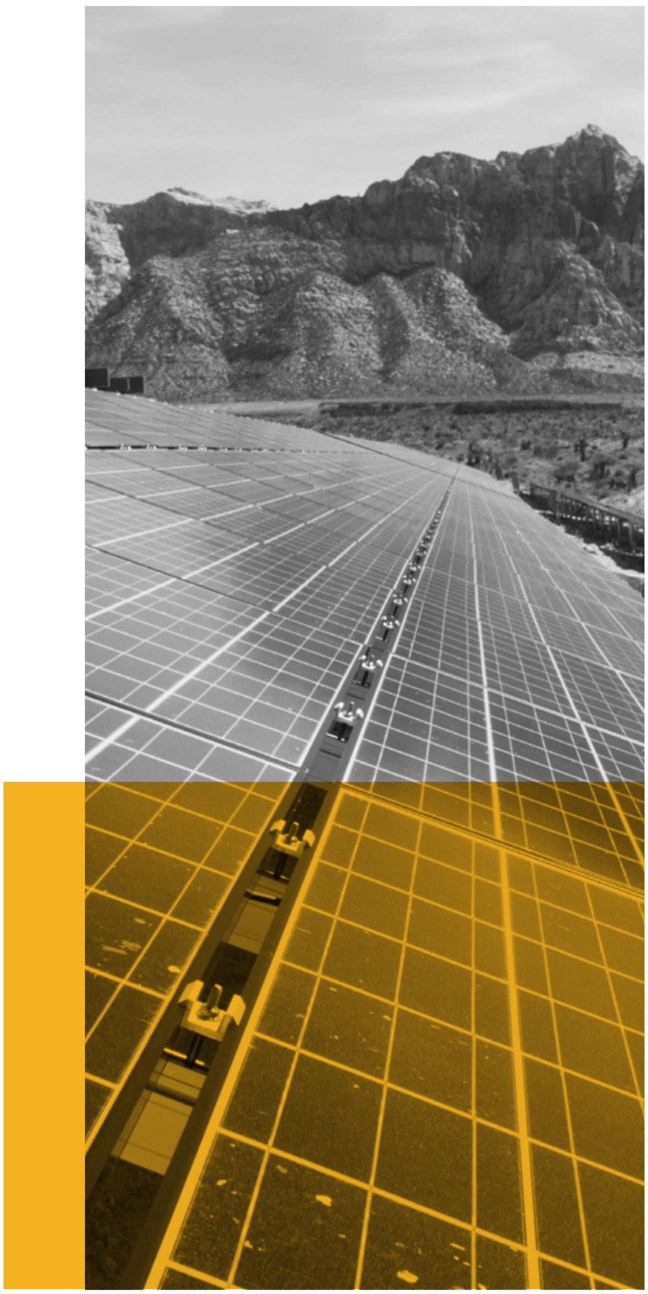
10 Eric O'Shaughnessy, et al., "Go Slow to Go Fast? A Review of the Impacts of Permitting on Large-Scale Solar Project Development" (Sept. 2025).

imposing statewide standards or override mechanisms.[11] This report does not attempt to resolve the abstract question of whether state control or local control is categorically preferable. [12] Instead, it asks what can be learned once a state decides to modernize its siting and permitting process: what kind of reform architecture it adopts, which bottlenecks that architecture actually resolves, what new seams or uncertainties remain, and what design choices appear to improve predictability, legitimacy, and project delivery in practice.

To assess how these reforms have functioned in practice, the report draws on statutory and regulatory analysis, stakeholder interviews, document review, and targeted quantitative indicators. It examines each state's principal reform statutes and related regulatory materials to identify the problems each reform was designed to address and the institutional structure it created. It draws on interviews with stakeholders directly involved in energy development and permitting—including developers, advocates, attorneys, permitting officials, local government representatives, and Tribal participants—to understand how these frameworks operate on the ground. The report also reviews implementation materials such as local ordinances, agency guidance, hearing records, legal decisions, and permitting documents to trace how reforms were interpreted and administered after enactment, and considers public project and permitting data, where available, to evaluate early implementation patterns. Taken together, these sources allow the report to assess how environmental review, public engagement, intergovernmental coordination, and judicial review interact with statutory timelines to support—or fail to support—real project delivery, and to identify lessons, best practices, and persistent gaps for a second generation of siting reform.

11 Robi Nilson, et al., "Outcomes and Timelines for State-Based Energy Facility Permitting in the United States" (Feb. 2026).
12 Sarah Everhart, "State Siting of Renewable Energy - Preemptive Power Grab or Power Play?" (Fall 2025).

2 CALIFORNIA



California's decarbonization pathway illustrates the tension between ambitious climate policy and the procedural realities of land use and environmental review. The Renewables Portfolio Standard (RPS) requires utilities to procure 60% of retail electricity sales from eligible renewable resources by 2030, and state policy commits California to 100% clean electricity by 2045. Planning and reliability proceedings at the California Public Utilities Commission (CPUC) anticipate a large volume of new capacity over the next decade, with continuing growth in solar and substantial expansion of storage to meet evening and seasonal reliability needs. Translating those plans and mandates into delivered resources requires a permitting framework whose timelines align with procurement schedules, federal tax-credit windows, and interconnection sequencing.[13]

Yet California's permitting experience is characterized by multi-year delays driven by local land-use discretion, protracted California Environmental Quality Act (CEQA) reviews, and parallel approvals.[14] In practice, developers are forced to build against several clocks at once. On the land-use and environmental side, projects may face local discretionary approvals, state permitting requirements, state and federal

13 Senate Bill 100, Cal. Pub. Util. Code section 399.11 et seq. (CA 2018)

14 California Environmental Quality Act, Public Resources Code Sections 21000, et seq. (CA 1970).

endangered-species review, and CEQA or the National Environmental Policy Act (NEPA) documentation.[15] On the transmission and interconnection side, they may face interconnection queue timing, transmission upgrades, the CPUC approvals for certain utility-side facilities, and in some cases additional federal approvals. While these layers reflect legitimate environmental and community protections, the challenge is that when the layers are not sequenced and bounded, they can convert protection into unpredictable delay without reliably improving substantive outcomes commensurate with the added time. This schedule risk can determine whether developers continue to pursue a project at all, particularly in jurisdictions where timelines and requirements are perceived as unbounded.

Early renewable developments often utilized the lowest-conflict sites near existing transmission infrastructure with supportive local governments. Over time, many of the easiest immediately available sites were developed, pushing additional projects toward landscapes with greater environmental sensitivity or community attachment. Rural residents, accustomed to open views and agricultural landscapes, voiced concerns about industrialization, health and safety, environmental impacts, and wildfire risk. Local boards of supervisors, responding to constituent pressure, exercised broad discretion under county zoning laws to deny projects despite positive staff recommendations and robust mitigation packages. Meanwhile, CEQA litigation became a powerful tool for project opponents. Even after a county certified an Environmental Impact Report (EIR), lawsuits could add two or three years of uncertainty and, if successful, require recirculation of studies.

Assembly Bill 205 (AB 205), enacted in June 2022, created an optional, statewide certification pathway at CEC for large clean-energy facilities and related infrastructure. The law centralizes CEQA lead-agency responsibility at the California Energy Commission (CEC or Commission), displaces most local discretionary land-use approvals, and binds the proceeding to a 270-day decision clock after completeness, paired with expedited judicial review. AB 205 conditions access to the state lane on enforceable community-benefit and labor requirements and preserves certain permits outside the CEC's direct authority.[16] Prior to AB 205, Senate Bill 7 created an expedited judicial-review pathway for certain large renewable projects in 2021, and Senate Bill 149 later in 2023 expanded and extended related streamlining tools.[17] AB 205's innovation was not therefore faster court review; it was to pair judicial streamlining with an opt-in CEC certification pathway that can displace most local discretionary siting approvals for qualifying projects. The sections that follow examine how the pre-AB 205 county-centric system created bottlenecks and how the new framework is performing in practice.

2.1 Pre-Reform Landscape

Prior to AB 205, utility-scale solar photovoltaic, onshore wind and storage projects were permitted only through use-permits issued by county boards of supervisors or planning commissions. Counties exercised broad land-use authority under state planning and zoning law, adopting general plans and ordinances that defined where energy infrastructure could

15 National Environmental Policy Act, 42 U.S.C. Sections 4321, et seq. (1970).

16 California Assembly Bill 205, codified in relevant part at Cal. Pub. Res. Code section 25545 et seq. (CA 2022).

17 Senate Bill 7 (CA 2021); Senate Bill 149 (CA 2023).

be sited. [18] The decentralized structure produced substantial variation in outcomes across jurisdictions. In Kern County, for example, where oil and gas production coexists with some of the world's largest wind and solar facilities, hundreds of megawatts (MW) of renewable projects were permitted through a streamlined programmatic EIR. Other counties, however, adopted restrictive ordinances or outright bans.

CALIFORNIA COUNTIES DEVELOP ANTI-RENEWABLE ORDINANCES

- Los Angeles County prohibited utility-scale wind projects in unincorporated areas such as the Antelope Valley and the Santa Monica Mountains.[19]
- San Bernardino County outlawed wind and solar facilities on more than a million acres of rural land, citing incompatibility with community character.[20]
- Contra Costa County's ordinance requires commercial wind turbines to be set back at least three times the tower's height from the wind project boundary and public rights-of-way, and at least 1,000 feet from existing offsite residences.[21]

Such zoning rules were often passed after a few controversial proposals sparked local opposition, turning what might have been case-specific disputes into general prohibitions. The recurring consequence was that siting feasibility was determined as much by local politics and process risk as by resource quality or statewide need.

Local discretion was further reinforced by CEQA, which required government agencies to identify, analyze, and mitigate significant environmental effects of proposed projects, and in some circumstances to address social or economic effects where they were linked to physical environmental change. County planning departments or boards typically served as the lead agency for CEQA review of renewables, preparing either a mitigated negative declaration or a full EIR. The law gave local agencies broad authority to determine the scope of analysis, the number of alternatives studied, and the adequacy of mitigation measures. It also allowed agencies to adopt statements of overriding considerations if significant impacts remain unavoidable. The combination of local land-use discretion and CEQA's substantive requirements meant that a county board could effectively veto a project, either by denying the permit outright or by imposing mitigation conditions that rendered the project financially infeasible.

Moreover, CEQA emphasizes public participation and allows any person to challenge an EIR or any other type of CEQA document in court. Opponents—ranging from environmental justice groups concerned about habitat loss to residents worried about views—often used litigation to delay or cancel projects. These lawsuits could take two or more years to resolve, during which developers incurred carrying costs and uncertainty. It is important to note that CEQA litigation is not the modal outcome of CEQA review and that many projects proceed without lawsuits; the

18 California Environmental Quality Act, Cal. Pub. Res. Code section 21000 et seq. (CA 1970).

19 Los Angeles County Code, Ordinance No. 2016-0069 (Nov. 2016).

20 Board of Supervisors of San Bernardino County, Resolution No. 2019-17 (Feb. 2019).

21 Contra Costa County Board of Supervisors, Ordinance No. 2011-04 (Apr. 2011).

procedural risk is therefore concentrated in certain geographies and controversy profiles rather than uniformly distributed.

Under the conventional county process, a utility-scale solar facility might require an EIR hundreds of pages long, with technical appendices on biological resources, cultural resources, hydrology, noise, air quality, agricultural impacts and alternatives. Consultants would conduct field surveys for sensitive species, analyze cumulative impacts with other projects and explore alternative site layouts. The process was sequential: data collection, analysis, draft EIR publication, public comment, response to comments, and final EIR certification. Opponents could challenge any perceived deficiency—from the choice of baseline conditions to the mitigation measure's feasibility. Even in counties supportive of renewables, these lawsuits created uncertainty that deterred investment.

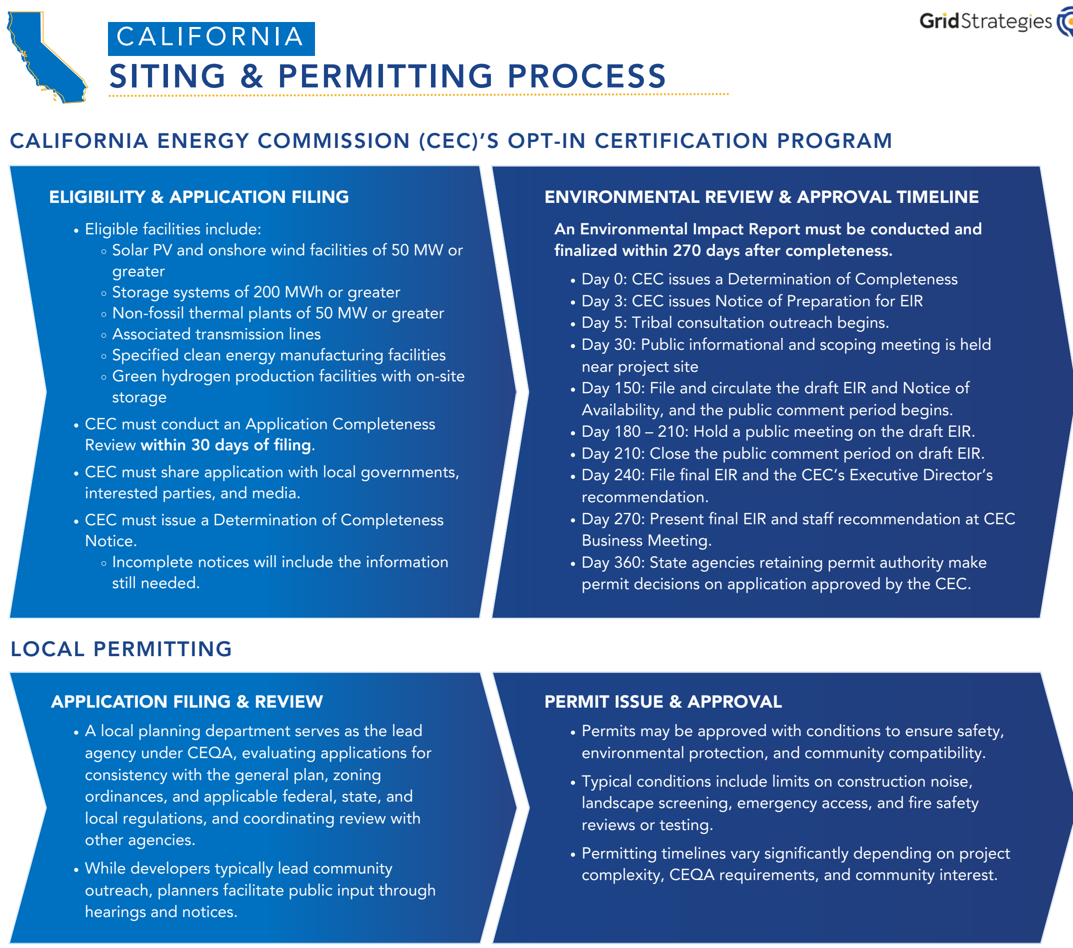


FIGURE 1. California Siting and Permitting Pathways and Process

The 90 MW Jacumba Solar project in San Diego County illustrates how CEQA litigation created delays and risk. After San Diego County approved the project in 2021, petitioners filed a CEQA challenge that raised, among other issues, claims about the adequacy of the EIR's impact analysis and impact characterization.[22] The Court of Appeal ultimately affirmed the County's

22 Rob Nikolewski, "'We've been completely plowed over': Residents of tiny San Diego County town sue to stop 600-acre solar project," *Los Angeles Times, (Sep. 2021).*

approvals in an opinion filed on January 23, 2024, rejecting those CEQA claims.[23]

CEQA lawsuits were only one avenue for opponents; political pressure on county boards often proved more decisive. More often, counties sought to avoid repeated project battles by amending their ordinances. San Bernardino County's 2019 Renewable Energy Conservation Element revised land-use policies to restrict large solar and wind projects in rural desert communities.[24] Inyo County effectively capped solar projects at 20 MW in most private land areas, citing viewshed and tourism concerns.[25] Napa County prohibited solar facilities in agricultural zones to protect vineyards.[26] This ordinance-making strategy meant that opposition became structural rather than project-specific. Developers responded by seeking sites in counties with more accommodating policies or by downsizing projects to fall below local thresholds. However, as the state's clean-energy targets required increasingly large installations, the supply of permissive counties dwindled.

Even after navigating local land-use permitting and CEQA, developers face a gauntlet of approvals from state and federal agencies, each with its own timeline and criteria. A typical solar project may require a Section 404 permit from the U.S. Army Corps of Engineers for jurisdictional wetlands, a Section 401 water quality certification from a Regional Water Quality Control Board, and, if habitat for listed species was present, an incidental take permit from the California Department of Fish and Wildlife. Projects subject to CEQA may require tribal consultation under AB 52, which can lead to redesign, additional mitigation, or confidentiality-related process constraints. Air districts issued permits for construction emissions, and projects near airports required Federal Aviation Administration (FAA) clearance. Transmission lines connecting the project to the grid required certificates of public convenience and necessity from the CPUC for investor-owned utility service territories or permits from municipal utility boards for public power areas. Each permit process operated sequentially, and delays in one could stall the entire project.

By the end of 2021, it had become increasingly clear that the existing permitting framework was incompatible with California's decarbonization timeline. Developers faced a risk profile in which entitlements could take five to seven years to obtain, making it very difficult to secure financing tied to production tax credit deadlines or CPUC procurement schedules. AB 205 was designed to respond to these challenges by establishing an opt-in state process for large clean-energy projects. The next part of this report will examine what AB 205 changed in law and practice, the early outcomes of this reform and the gaps that remain.

2.2 Reform Early Outcomes

AB 205 introduced a structural realignment in California's approach to siting large clean-energy facilities by offering an opt-in, consolidated state review at the CEC. Under AB 205, eligibility generally includes utility-scale solar and onshore wind (≥50 MW), storage systems (≥200 MWh), certain geothermal, biomass, and clean-energy manufacturing facilities, and related gen-tie

23 Jacumba v. San Diego Cnty. Bd. of Supervisors, D081148 (CA 2024).
24 San Bernardino County, Resolution No. 2019-17.
25 County of Inyo, "Renewable Energy General Plan Amendment Final Program Environmental Impact Report Volume II of II," (Mar. 2015).
26 Napa County Board of Supervisors, "CEQA Memorandum for Renewable Energy Systems Zoning Ordinance Text Amendment," (Dec. 2019).

or hydrogen infrastructure. Once an applicant invokes AB 205, the CEC acts as the CEQA lead agency and exercises permitting authority in lieu of most local discretionary approvals, while leaving certain real-property and access-related issues unresolved. The statute does not displace permits issued by the State Lands Commission, the Coastal Commission, Regional Water Quality Control Boards or other "specialist" agencies. These entities remain responsible for water quality certification, coastal consistency, sovereign land leases, and hazardous materials oversight, but they must coordinate with the CEC and issue any residual permits within a defined window after certification.[27]

Once the CEC deems an application complete—after verifying that the project description, environmental baseline data and study methodologies meet its standards—the Commission must issue a final decision within 270 days. This statutory clock compresses the environmental review and decision schedule that previously stretched for years. The statute further structures the timeline through specific milestones. Within five days of completeness, the CEC must invite government-to-government consultations under AB 52 to engage Tribes in identifying cultural resources. Within 30 days, staff hold a scoping meeting near the project site to solicit public comment and refine the scope of analysis. By day 150, staff must publish a draft EIR and their initial staff assessment, which triggers a 60-day public comment period. A final EIR and revised staff assessment must appear by day 240, giving intervenors and decision makers time to review the record before the Commission's public vote around day 270. If litigation ensues, the statute directs courts to resolve cases on an expedited basis. This accelerated track is not a guarantee that lawsuits will be absent; rather, it is a procedural safeguard intended to prevent multi-year court delays from undermining project financing.[28]

Applicants are required to negotiate binding community benefit agreements with local jurisdictions or community-based organizations, ensuring that host communities share in the economic gains associated with large renewable projects. Projects must use a skilled and trained workforce, with prevailing wage and apprenticeship ratios that effectively deliver union-level labor standards. The CEC must also find that an opt-in project provides an overall net positive economic benefit to the local government whose permitting authority is displaced. Furthermore, AB 205 authorizes the Commission, in limited circumstances and on a demanding showing tied to public convenience and necessity, to approve a project notwithstanding conflicting local standards; this authority is consequential and must be justified on a project-specific record. [29] Developers gain a predictable, unified permitting timeline, but they must demonstrate that their projects deliver tangible economic, labor, and community benefits and satisfy rigorous environmental and cultural protections.[30]

The CEC began accepting applications under AB 205 immediately after its enactment in mid-2022, and within two years the opt-in docket offered the first insights into how the streamlined pathway functions in practice. Early applicants included some of the largest clean-energy projects ever proposed in California. Among the first cases were the Fountain Wind project in Shasta County and the Darden Clean Energy Project in Fresno County.

27 California Assembly Bill 205 (CA 2022).
28 Id.
29 Id.
30 Id.

A TALE OF TWO PROJECTS

Fountain Wind was a proposed 205-MW wind facility on approximately 2,855 acres of forested land in Shasta County. The project went through a multi-year EIR and was unanimously denied by the county planning commission (5-0) in June 2021 amid vocal public opposition. The Board of Supervisors upheld the denial by a 4-1 vote in October 2021. Critics cited aesthetic impacts, wildfire risk, interference with aerial firefighting, and cultural resource concerns, but opposition was also significantly shaped by sustained objections from the Pit River Tribe and other Tribal participants, making Fountain Wind an important test of how AB 205 handles Indigenous cultural-resource claims and tribal sovereignty concerns. After the county's denial, the developer sought AB 205 certification; CEC staff later recommended denial because of significant, unavoidable environmental impacts and conflicts with local land-use laws. On November 19, 2025, the CEC noticed consideration of the Executive Director's recommendation for its December 19, 2025 business meeting, and on December 19, 2025, the Commission unanimously adopted a final order denying the application. The order also acknowledged a separate dispute between the developer and Shasta County regarding reimbursement of the county's review costs and directed that issue into the CEC's separate dispute-resolution process.[31]

This case demonstrates how, under the pre-AB 205 process, a single county could halt or materially delay a project of statewide significance, and how, even under the new state process, unresolved concerns about environmental and cultural impacts can still lead to denial.[32]

Darden Clean Energy Project provides a contrasting example of an approval under AB 205, and it is also the strongest early evidence that a complete application can

31 California Energy Commission (CEC), Fountain Wind Energy Project docket materials (2024-2026).

32 Kurtis Alexander, "A California Law Was Supposed to Fast-Track Renewable Energy. The State Just Shot Down a Key Test Case," San Francisco Chronicle, (Dec. 2025).

move to a final decision within the statutory 270-day window. Darden, which was proposed by IP Darden I, LLC, combines a 1,150-MW solar facility with up to 4,600 megawatt-hours (MWh) of battery storage on roughly 9,500 acres in western Fresno County, including land no longer able to support agricultural production. After the CEC deemed the application complete on September 19, 2024, the Commission certified the project on June 11, 2025, a timeline consistent with AB 205's decision clock. However, certification did not immediately authorize all construction activities at once. The post-certification phase instead proceeded in stages: the CEC issued limited authorizations for early work before issuing the Full Notice to Proceed with Construction Activities on January 23, 2026, after the developer satisfied the remaining preconstruction Conditions of Certification. Upon approval, the project was also described by the CEC as the world's largest solar-plus-battery storage project, with the battery component expected to be the largest battery energy storage system in the world once built. The record also illustrates that AB 205's labor and community-benefit requirements included more than $2 million over ten years and estimates on the order of 2,000 prevailing-wage construction jobs, alongside commitments to a skilled and trained workforce.[33]

Darden's success may reflect favorable site characteristics and early stakeholder alignment rather than solely the statutory pathway. The record did not identify significant and unavoidable impacts. The developer also held numerous community meetings, job fairs, and local business events, and agreed to approximately $65 million in local purchases in addition to substantial local tax contributions. The project also includes a new point of interconnection that may facilitate additional renewable development in western Fresno County, including on retired agricultural land often viewed as comparatively low-conflict from a siting perspective. AB 205's performance should therefore be evaluated across a broader set of dockets, including projects in higher-conflict geographies.

Even with these illustrative cases, the successes of the opt-in program are small compared to California's overall build-out needs, and the small sample size limits broad conclusions that can be drawn at this stage. As of early 2026, the CEC's Opt-In Certification Program page listed roughly ten proposed projects in various stages of review, and only a subset had reached completeness determinations.[34] That limited docket count suggests that AB 205 is being used selectively, likely where developers perceive the county pathway as especially risky. There are other factors that would explain why developers use AB 205 selectively. For example, the AB 205 requirements, along with the program's procedural intensity, can increase upfront transaction and compliance costs. The next section of this report examines residual gaps and proposes a suite of recommendations aimed at converting the opt-in program into a reliable deployment engine.

33 CEC, "Final Order" (June 2025).
34 CEC, Opt-In Certification Program dashboard and docket materials (accessed Mar. 2026).

FIGURE 2. Projects currently moving through the CEC's Opt-In program as of March 2026[35]

2.3 Identified Gaps and Bottlenecks

The early operation of California's opt-in siting process offers initial lessons about where the statute succeeds and where it still fails to deliver the kind of predictable, financeable closure that procurement schedules and reliability planning implicitly assume. The statute compresses the formal proceeding once Day 0 begins, but it leaves multiple pathways for delay and outcome uncertainty to reappear elsewhere in the process. These structural gaps continue to convert time into a substantive variable, magnify litigation opportunities, and weaken confidence that an approval will translate into construction and energization on the timelines needed to meet climate and grid-reliability obligations.

Partial Consolidation and Residual Permits: AB 205 is frequently described as a one-stop permit, but its legal design is closer to a centralized hub than a single, all-encompassing authorization.[36] The CEC's certification supplants most county entitlements and consolidates CEQA lead-agency responsibility, yet several other authorities remain independent by statute, including Clean Water Act Section 401 certifications issued by the Regional Water Quality Control Boards, sovereign land leases administered by the State Lands Commission, and coastal approvals within the Coastal Commission's jurisdiction.[37] Additional retained authorities may also be implicated depending on the project's location, configuration, and interconnection requirements.

The program's coordination mechanism—requiring certain agencies to act within a defined window after certification—helps, but it does not eliminate the core bankability problem

35 Id.

36 California Assembly Select Committee on Permitting Reform, "Final Report" (Mar. 2025).

37 California Public Resources Code Section 25545.1 (CA 2022); California Public Resources Code Section 25545.7 (CA 2022); California State Water Resources Control Board, 401 Water Quality Certification and Wetlands Program (Jan. 2026).

created by retained authority. A project can complete the state's principal review process and still face late-arising conditions, monitoring requirements, or redesign demands from external agencies that materially alter cost, constructability, or schedule. That dynamic makes the post-certification phase a source of sequential risk rather than the concurrent finish line the reform was intended to provide. It is especially destabilizing where external permit conditions require changes that ripple backward into mitigation commitments or construction sequencing that had been treated as settled during the CEC proceeding.

A similar dynamic can arise even where the CEC is able to incorporate a biological authorization into the certification process, most notably under the California Endangered Species Act (CESA).[38] Although AB 205 can streamline the procedural pathway, it does not remove CESA's substantive standards or the practical influence of CDFW on species-related mitigation and project design. Where a project implicates listed or candidate species, or habitat conditions that create take risk, the need to support avoidance, minimization, mitigation, and biologically defensible certification conditions can continue to drive schedule and redesign risk. The practical consequence is significant: AB 205 may accelerate the core certification proceeding while leaving one of the state's most consequential biological constraints substantially intact. Without material improvement in how CESA-related review is scoped, sequenced, and integrated, the statute will continue to under-deliver on predictability for many of the projects California most needs to build.

Residual permits and permissions also persist in forms that do not always present themselves as traditional permits, yet can still determine whether construction can begin. Even where county land-use discretion is displaced, local governments may retain leverage through encroachment permits, oversize-load routing approvals, traffic-control permissions, road-use agreements, and the granting of easements, franchises, or other property-based access instruments for gen-tie corridors and construction staging. In some cases, county ownership or control of roads serving substations or other key facilities can effectively leave local governments as the binary decision-maker despite the state process. Because these approvals are often administered outside the headline AB 205 calendar, they can recreate a bargaining channel after certification and, in jurisdictions resistant to state preemption, function as practical choke points even when the primary entitlement has shifted to the state. Where these residual gates remain schedule-determinative, developers may conclude that AB 205 redistributes risk more than it materially reduces overall project uncertainty.

Although AB 205 displaces core local land-use approvals, it does not necessarily resolve whether those property-based instruments fall within the practical reach of the state certificate. In many cases, local jurisdictions may still treat access across city or county property as a separate discretionary action, potentially subject to its own procedural requirements and CEQA exposure. That reality undercuts one of AB 205's central promises: even after the state removes the principal entitlement decision from local elected bodies, project-critical elements may still be returned to local control through the law of access and property rather than zoning. For many projects, this is among the most consequential binary risks and a significant reason a developer may decide early that the AB 205 pathway is not worth pursuing. If the Legislature

38 California Endangered Species Act, Fish and Game Code Sections 2050, et seq. (CA 1970).

intends AB 205 to function as a truly effective statewide siting tool, it should clarify how critical access and corridor-assembly issues will be resolved and whether additional state tools are needed to prevent local control over access from operating as a de facto veto.

CEQA's Substantive Weight and Litigation Exposure: AB 205 compresses process, not substantive standards, and this distinction is a key reason why streamlining has not translated into uniformly lower risk. The CEC remains obligated to prepare a full EIR that satisfies CEQA's ordinary requirements, including robust baseline analysis, a defensible alternatives framework, feasible mitigation, and lawful findings where significant impacts remain. The statute does not create a clean-energy substantive override that automatically weighs statewide decarbonization and reliability benefits against localized environmental harms, which means projects that implicate sensitive habitat, prime farmland, wildfire-risk environments, or cultural resources remain exposed to the same significance thresholds and the same litigation hooks that shaped outcome under county-led CEQA. Fountain Wind's denial illustrates the consequence of that substantive continuity. A state forum can centralize while still concluding that impacts are significant and unavoidable and cannot be justified on a defensible record.

The AB 205 expedited judicial review provisions are best understood as time control rather than risk control. They can shorten the duration of a CEQA challenge, but they do not materially reduce the likelihood of filing, narrow standing, or eliminate the possibility of remand and corrective analysis that reopens schedule and cost exposure at the worst possible point in a project's financing cycle. Because the threat to bankability is often driven less by the merits of a lawsuit than by the possibility of a court-ordered rework that destabilizes procurement alignment, tax credit timing, and construction contracting, the persistence of ordinary CEQA litigation exposure continues to shape both applicant behavior and agency posture.

Voluntary Opt-In and the Concentration of Conflict: AB 205's elective design was a political compromise, but it has produced a structural selection effect that shapes how the program is perceived and how it functions. Developers choose the state pathway when they expect local denial, unbounded delay, or a controversy profile that threatens county-level closure, while projects in cooperative jurisdictions or in counties with predictable processing often remain local to avoid the much higher AB 205 cost burden and the political escalation that a state proceeding can trigger. The result is that the CEC docket is populated disproportionately by more challenging cases, including projects with intense local opposition, sensitive resource conflicts, difficult alternatives disputes, or novel technology profiles such as large battery storage. This concentration makes the program appear slower and more controversial than a representative sample would suggest, and it intensifies staff incentives to harden each record defensively because a remand in a high-visibility state forum risks undermining confidence in the reform itself.

AB 205's political durability has been shaped from the outset by the fact that the statute was enacted through a budget trailer bill and that many affected constituencies—industry and local governments alike—did not view themselves as participants in its design. That history contributed to early distrust and legitimacy concerns before performance could be fully evaluated. The voluntary structure further means AB 205 cannot, by itself, reset statewide permitting culture. As long as counties retain primary control over a large share of the project universe and can adopt restrictive ordinances or moratoria, the opt-in program will process only a subset of the portfolio needed for delivery on statewide decarbonization targets. In practical deployment terms, a safety valve can be valuable without being sufficient. The state can resolve certain stalemates, but it cannot rely on selective uptake alone to produce the throughput required across all viable regions.

Limited Pre-Emption and Persistent Local Leverage: AB 205 provides an alternative forum for some projects, but it does not automatically override local rules. The Commission must still evaluate local laws, ordinances, regulations, and standards (LORS), and can override local inconsistency only through demanding public-convenience-and-necessity findings. To date, that override authority has been used cautiously, which means the existence of restrictive local ordinances still shapes whether AB 205 offers a realistic off-ramp. Where a project conflicts with local ordinances or general plan policies, the CEC must either find compliance or make a demanding public convenience and necessity determination, including a showing that no more prudent and feasible means of meeting the public need exists. This standard does not presume that statewide decarbonization targets automatically outweigh local land-use law, and it creates meaningful outcome uncertainty in precisely the cases most likely to be routed into the opt-in pathway. In practice, commissioners may be reluctant to overrule local governments without overwhelming evidence, not only because of legal posture but because visible state preemption carries political optics and legitimacy risk that the Commission must manage as an appointed body.

Even where preemption is legally strong, local influence can persist through cooperation channels that sit adjacent to formal land-use discretion. Counties and local agencies may control access and construction interfaces through rights-of-way administration, road encroachment permissions, oversize-load routing, or the granting of property-based instruments needed to assemble corridors and staging areas. These are not always framed as permitting, but they can still become de facto veto points when local relationships are adversarial because a project that cannot lawfully or practically move heavy equipment, secure corridor access, or coordinate construction traffic cannot execute on its schedule even if its core entitlement is approved. In sum, the AB 205 program is the permitting venue of last resort and provides negotiating leverage for developers against hostile local governments who might worry that they would lose all control if the developer could just go to the CEC instead. However, developers are unlikely to get around some of these restrictive ordinances by opting into the AB 205 process.

Inconsistent Completeness Criteria and Moving Goalposts: Because AB 205's statutory timeline begins only after the CEC deems an application complete, completeness has become the real schedule-determinative gate and, increasingly, a de facto defensibility screen rather than a ministerial intake step. In a compressed post-completeness calendar, staff have strong incentives to stabilize the project description, baseline studies, consultation posture, mitigation concepts, and even engineering detail before starting Day 0. Late-emerging issues can force redesign, expand procedural vulnerability, and increase remand risk. As a result, the statute's headline 270-day promise can be undermined by an elastic pre-clock period that is not captured by formal metrics.[39]

39 Noah Baustin, "When 270 Days Becomes 650," POLITICO, (Aug. 2025).

That risk is compounded by the absence of transparent, standardized completeness criteria that reduce variance across cases. Seasonal biological survey windows can force multi-month delays. Alternatives analysis remains one of the most litigated aspects of CEQA, encouraging exhaustive early screening. Tribal cultural resources work requires a defensible record while also protecting confidentiality, which often leads to iterative protocol development rather than straightforward submission. In practice, applicants can experience completeness less as rule-based intake than as negotiation, making it difficult to schedule, budget, and underwrite the path to Day 0 in a way capital providers regard as reliable.

The problem does not end once an application is deemed complete. Even after the statutory clock begins, staff and participating agencies may continue to issue broad or iterative data requests, demand refinements to methodologies, or condition progress on supplemental submissions that are not tightly bounded by rule or commissioner-level oversight. That dynamic can dilute the practical value of the 270-day timeline by giving staff, participating agencies, and other stakeholders substantial leverage to prolong negotiations, reshape mitigation packages, or defer contested issues without formally extending the clock.

A major driver of the prolonged completeness phase, according to stakeholder accounts and emerging docket practice, appears to be the CEC's interpretation of AB 205 as requiring the Commission, when certifying a project, to stand in the shoes of local governments for a broad range of equivalent local approvals. Current staff practice has at least in some cases been understood to encompass approvals such as grading and building permits, prompting requests for engineering packages at roughly 60 to 90 percent design during the application stage. That approach is in tension with CEQA's intended function as a planning-level review process, which is supposed to preserve room for alternatives analysis and design evolution rather than lock in near-final engineering before environmental review is complete. Requiring that level of precision too early creates a false sense of closure and may increase, rather than reduce, downstream risk: once mitigation measures are imposed, projects may require substantial redesign, potentially enough to trigger supplemental CEQA review and add months of delay. While Darden—the first project to move through this process—may not yet reveal this bottleneck, the structure of the program suggests that the problem is likely to become more visible as additional projects advance.

Expansive Conditions of Certification and Post-Permit Uncertainty: Even when the CEC issues a certificate, the conditions can create a second closure problem. Conditions are essential because they translate mitigation, monitoring, safety, and community benefit commitments into enforceable obligations, but bankability turns on whether those obligations are bounded and priceable at the moment a project must lock its engineering, procurement, and construction (EPC) scope, insurance assumptions, and financing terms. When conditions are expressed as clear performance standards, fixed mitigation actions, and defined compliance milestones, they can be integrated into contracting and scheduling. When conditions instead require multiple post-permit management plans subject to iterative agency approval, adaptive management that can expand over time, continuous third-party verification without clear ceilings, or ongoing signoffs that can hold construction sequencing hostage, certification begins to resemble preliminary authorization rather than durable closure. Compliance costs under AB 205 also appear to be materially higher than under many local permitting pathways.[40]

This dynamic is particularly acute for battery storage and hybrid facilities because safety legitimacy is not satisfied by a CEC analysis alone; it also depends on credible emergency response integration and operational controls that local responders must treat as real and executable. Local battery-storage moratoria and evolving safety expectations can function as a parallel siting gate, pushing some projects toward AB 205 while simultaneously increasing demands for detailed, operationally credible safety and emergency-response commitments. Where safety conditions remain open-ended or subject to evolving interpretation, applicants can struggle to price the obligations with confidence, and counterparties may discount the value of the approval even when the formal proceeding was accelerated.

Land-Use Identity Conflicts: California's build-out has moved beyond the era in which large projects could be routinely sited on low-conflict parcels near existing infrastructure. As remaining viable sites increasingly overlap with landscapes that carry strong cultural, ecological, and agricultural identity, individual projects become proxies for broader regional land-use disputes. In this land-use referendum environment, acceleration can intensify resistance rather than reduce it, because speed is interpreted as diminished local control and therefore as a reason to fight earlier, harder, and more publicly. The practical implication is that controversy expands the CEQA surface area by making core framing questions—significance, feasible alternatives, cumulative conversion, and the credibility of mitigation—more contested and more politically salient, which in turn increases the rational incentive for defensive record thickening and pre-clock delay.

Agricultural regions—particularly the San Joaquin Valley—illustrate the siting challenge sharply.[41] Here, land conversion debates are deeply intertwined with water scarcity, farmland preservation, and rural identity.[42] As groundwater constraints and economic shifts under the Sustainable Groundwater Management Act push vast acreage out of irrigated production, state modeling points to this retiring farmland as a low-conflict venue for solar and storage.[43] However, a permitting paradox has emerged: while the state counts on this land transition for its clean-energy build-out, its core land-status tools penalize the shift. Current CEQA practice often treats solar on recently fallowed parcels as a significant conversion of agricultural land, requiring costly mitigation. Simultaneously, Williamson Act[44] contracts can block or delay conversion because cancellation remains at the discretion of local officials and cannot legally occur until the years-long CEQA process is complete. Furthermore, these instruments introduce buildability constraints that a CEC certificate does not automatically dissolve. A developer may secure a principal state approval only to remain stalled by separate local administrative barriers. When these disputes are not resolved upstream through broad land-transition policies, the Commission is forced to adjudicate regional conflicts through project-specific records—a process that is difficult to standardize and highly vulnerable to litigation leverage.

40 CEC, "Darden Clean Energy Project," (Accessed Mar. 2026); CEC, "Fountain Wind Project," (accessed Mar. 2026).

41 Rachel Becker, "California May Help Solar Bloom Where Water Runs Dry" CalMatters, (Sept. 2025)

42 Camille Von Kaenel, Wes Venteicher, "A New Survival Strategy for Central Valley Farmers," *POLITICO, (Oct. 2024).*

43 Public Policy Institute of California, "Solar Energy and Groundwater in the San Joaquin Valley," (Oct. 2022).

44 The California Land Conservation Act of 1965, better known as the Williamson Act, enables contracts between landowners and local governments to voluntarily restrict development on parcels for a minimum of ten years in exchange for lower tax assessments.

Deliverability and Interconnection Mismatch: Permitting acceleration alone does not ensure that projects can connect to the grid on the timelines assumed by procurement and reliability models. California's major transmission upgrades and new lines proceed on separate calendars with their own constraints and approval pathways. In that environment, AB 205 can potentially produce faster siting decisions while still leaving a project stranded behind network upgrades, deliverability constraints, or multi-year transmission construction schedules that dominate actual commercial operation dates.[45] Without stronger integration between siting acceleration and grid-realization pathways, the state risks producing a pipeline of permitted but non-deliverable projects, undermining both public trust and the economic value of the expedited forum.

In summary, these gaps explain why AB 205, while a landmark structural reform, has not yet produced a uniformly predictable infrastructure delivery pathway. The state has demonstrated that it can run a disciplined, time-bound state review process after completeness, but repeatable, financeable outcomes will depend on whether the program can reduce variance in its entry gates, narrow the post-certification permit tail, convert conditions into commercially legible obligations, and integrate siting acceleration with the grid-realization constraints that ultimately determine whether permitted projects deliver power when the system needs it.

2.4 Recommendations

The gaps identified in the previous section highlight the specific places where an accelerated permitting lane still fails to produce repeatable, construction-facing closure. The recommendations below are therefore oriented around converting AB 205 from an exceptional forum used mainly for crisis cases into a normalized infrastructure delivery system.

Make Completeness Review Transparent and Paired with a Disciplined Pre-Application Gate: Because the statutory clock begins only after an application is deemed complete, the completeness phase has increasingly become the program's real risk gate. In a compressed calendar, staff have strong incentives to push uncertainty upstream in order to avoid remand-prone records once the clock begins. Completeness becomes ineffective when it operates as an elastic negotiation rather than a predictable intake standard. The CEC should therefore convert completeness into a rule-governed gate with published checklists by project class, sample survey protocols, defined engineering data standards, and a clear alternatives framework that reflects how the Commission expects site constraints to be handled. The objective should be to ensure that applicants can plan backward from stable requirements rather than discover sufficiency expectations iteratively.

That framework should be coupled with a structured pre-application process that forces early convergence on the issues most likely to trigger rework such as biological survey methods and seasonal windows, Tribal consultation, and alternatives scoping. This front-end gate should instead serve as the mechanism that protects the 270-day promise from becoming a headline metric divorced from real project duration. Most importantly, the CEC should expressly clarify

45 California Public Utilities Commission, "Decision Requiring 2029-2032 Electric Resource Procurement and Transmitting Portfolios for 2026-2027 Transmission Planning Process," Proposed Decision, Rulemaking 25-06-019 (Jan. 14, 2026).

that AB 205 review operates through a two-step structure. The first step should be a planning-level review sufficient to evaluate environmental impacts, alternatives, mitigation, and overall site suitability. The second step should be a detailed engineering review prior to Notice to Proceed, covering implementation-level matters such as final grading, construction, and design details. That distinction is critical. CEQA is intended to function as a planning-level process, not as a requirement to lock in near-final engineering before environmental review is complete. Treating completeness as if it requires final engineering too early creates a false sense of precision, reduces room for alternatives and design evolution, and may ultimately increase the likelihood of redesign and supplemental CEQA work after mitigation is imposed.

Although checklists can ossify practice and exclude novel mitigation approaches, that risk can be managed by treating them as minimum requirements and allowing alternative showings where applicants satisfy an equivalent performance standard. The CEC should publish project-type guidance specifying which surveys, modeling, mitigation plans, consultation materials, and engineering details must be present at filing, and which may appropriately be supplied later during the engineering stage before Notice to Proceed. Because early engagement is only meaningful when stakeholders can participate effectively, the state should pair this structure with targeted technical assistance for under-resourced Tribes and counties, so consultation does not become delayed simply because the parties with legitimate interests lack staff capacity to engage on schedule. The same guidance should also place guardrails on post-completeness data requests by distinguishing between genuinely new information needed to evaluate significant impacts and iterative requests that should instead be handled through bounded supplementation, fixed response windows, and commissioner-visible escalation when disputes threaten to consume the statutory schedule.

Convert the CEC from a Coordinating Hub into a True One-Stop Decision: California should clarify, in statute or regulations, the residual permits and approvals that remain outside AB 205 certification and how those permits will be sequenced with the CEC decision. The opt-in pathway reduces fragmentation, but it does not automatically bind every approving entity, which means that projects can still face many-doors dynamics after certification. While complete preemption is neither legally nor politically feasible for all permits, the CEC could publish permit-mapping guidance that identifies common state, federal, and local permits that remain relevant even in opt-in cases. That clarification should expressly address project-critical real-property instruments—such as franchises, easements, and local rights-of-way for gen-tie and collection infrastructure—and specify whether they are displaced, coordinated, or left for separate local action.

Moreover, the CEC could formalize interagency consultation protocols with agencies such as the Department of Fish and Wildlife, regional water boards, and air districts. Publishing a standardized permit inventory early in each docket would help prevent late discovery of critical-path authorizations. Additionally, the CPUC and CEC should clarify, through an MOU or similar mechanism, how AB 205 decisions interact with IOU-related project elements triggered by large-generator interconnection upgrades. California should consider whether AB 205 remains best designed as a purely voluntary lane or whether certain categories of projects—such as large, high-priority resources identified in state planning—should be routed into a statewide process by default. If the state moves toward default routing, it should do so only with clearly articulated criteria, robust engagement requirements, and transparent benefit frameworks that make the statewide choice defensible rather than merely expedient. Particular attention should be given to biological review under CESA, where earlier issue-framing, clearer mitigation expectations, and tighter integration with the AB 205 schedule could reduce one of the most persistent sources of post-filing uncertainty.

Standardize Mitigation Conditions: The state should build a standardized library of conditions and mitigation playbooks for recurring impact categories—biological resources, wetlands, cultural resources, noise, decommissioning, and battery safety—drafted as bounded performance standards with clear verification methods. The purpose is to reduce bespoke reinvention and narrow litigation surface area by making the default compliance architecture legible and repeatable. Where a project adopts the standard package, the program should treat it as presumptively adequate absent site-specific reasons to deviate, while departures should require explicit justification in the record. Over time, a condition library becomes both a learning system and a risk-control tool. It would reduce the incentives for opponents to treat every docket as an open-ended negotiation over baseline sufficiency, and the pressure on staff to solve common issues through increasingly elaborate and individualized conditions.

Standardization should also apply equally to the statute's labor and community benefit architecture. AB 205's legitimacy depends on a visible exchange of speed and consolidation in return for enforceable local value. That exchange becomes slower and less credible when community benefit agreements and net-positive findings are negotiated from scratch each time. The Commission should publish model community benefit terms, standard methodologies for demonstrating overall net positive economic benefit, and consistent compliance reporting structures for prevailing wage and skilled-and-trained workforce requirements. Done properly, the use of templates does not eliminate local tailoring; it establishes a stable floor that reduces negotiation churn, improves equity by preventing under-resourced communities from being forced into one-off bargaining, and makes the benefit bargain more transparent to constituents whose acceptance ultimately governs social durability.

Create a Renewable-Specific Environmental Review Pathway: Beyond AB 205, California should establish a clean energy-specific environmental review framework that preserves rigorous protection while reducing the bespoke analytic burden that makes records slow to produce and easy to litigate. The current model accelerates timeline without redesigning the documentation architecture, which encourages staff and applicants to respond to litigation risk by thickening the record rather than making it more standardized and decision-centric. A purpose-built pathway would push more of the recurring impact analysis upstream into programmatic work, establish presumptive mitigation packages and exclusion zones, and narrow project-specific alternatives fights to genuinely site-specific trade-offs rather than forcing each docket to re-litigate foundational policy questions. A well-designed framework can also make preemption clearer and more durable by distinguishing legitimate local conditions that refine mitigation from local ordinances that operate as de facto bans inconsistent with statewide deployment needs.

The core design principle must be objective with uniform eligibility and enforceable standards. If the pathway is to reduce variance rather than merely relocate it, covered projects must be able to qualify by demonstrating compliance with clear siting and mitigation rules, and opponents must have fewer incentives to treat minor analytic disputes as a delay strategy. This is the structural move that turns permitting from litigation by omission into a compliance-oriented approval system where the central question is whether the project meets known requirements, not whether the record can be attacked for marginal analytical shortcomings.

Integrate Siting with Grid Planning and Interconnection: Permitting reform cannot succeed if transmission and interconnection remain the binding constraints on real-world delivery. The state should align AB 205 certification more tightly with interconnection reality by screening expedited-lane eligibility for credible grid pathways, prioritizing projects located in zones with planned upgrades or demonstrable deliverability, and integrating the CEC review milestones with the interconnection queue and transmission planning timelines. This is about preventing the state from accelerating the most visible controversies while leaving benefits deferred by grid constraints, which undermines legitimacy and reduces the economic value of speed.

California should also strengthen its capacity to deliver shared transmission that serves multiple projects rather than forcing each proposal to carry bespoke network risk. Whether through a dedicated transmission development authority or expanded powers for an existing entity, the state needs a mechanism that can plan, finance, and build backbone upgrades on a schedule that matches the deployment implied by procurement. When siting acceleration is synchronized with grid realization, approvals translate into energization, communities see tangible system benefits sooner, and the state avoids building a pipeline of permitted-but-stranded projects that erodes confidence in both reform and climate policy.

Embed Front-End De-Risking and Local Capacity Support: A predictable siting regime depends on public trust and meaningful participation, particularly in a post-easy-siting environment where projects are experienced as land-use referenda. California should formalize a front-end de-risking phase that requires early engagement with Tribes, local governments, emergency responders, and resource agencies, and it should back that engagement with technical assistance so under-resourced communities can participate as informed counterparts rather than as late-stage objectors. This is not merely an equity measure—it is a risk-control strategy. When communities lack credible independent information, uncertainty hardens into opposition, which increases the incentive for litigation and forces staff to thicken records defensively. When local capacity is real, disputes become bounded and design-specific, which is the only kind of disagreement that a standardized state permitting program can reliably resolve.

If California implements these reforms as an integrated package—normalizing state routing, integrating retained-authority permits into one record, standardizing mitigation and the social bargain, rule-governing completeness, building closure into certification, redesigning the environmental review container, and synchronizing siting with grid delivery—the state can preserve AB 205's core trade while converting early promise into repeatable, financeable outcomes. The objective is a permitting process that produces predictable schedules and equitable benefit distribution at the scale required by California's statutory decarbonization commitments.

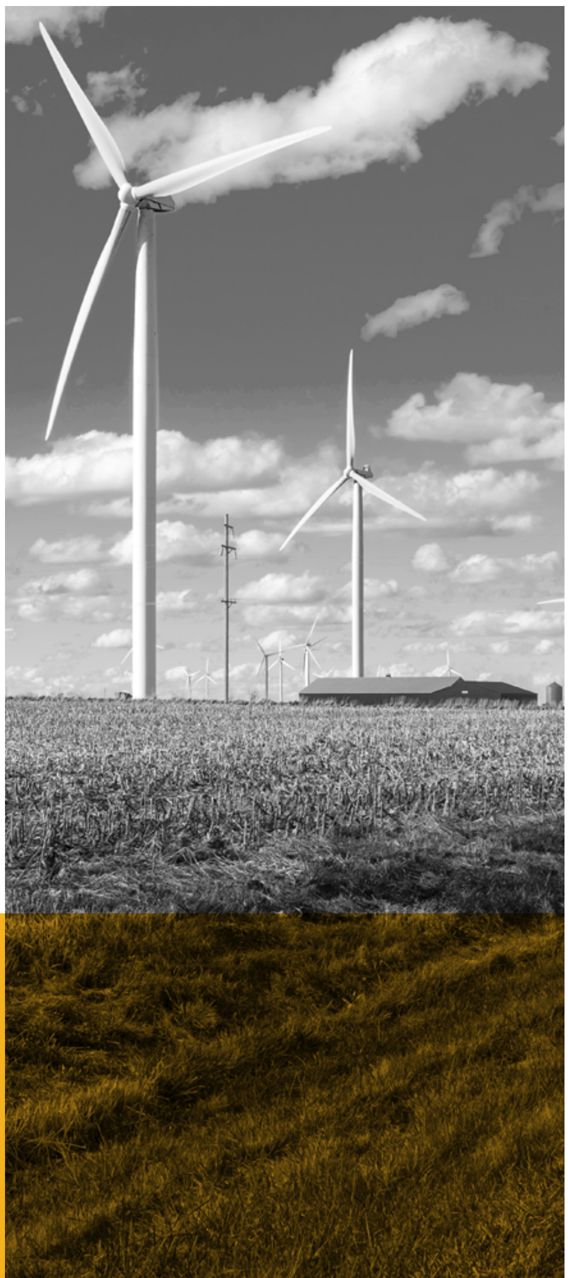
2.5 Conclusion

AB 205 creates a statewide, time-bound pathway that can deliver both approvals and denials on a consolidated record. The Darden approval and the Fountain Wind denial demonstrate that the program can reach a dispositive statewide decision on a schedule that is, at least in those cases, faster and more predictable than many county CEQA pathways. However, AB 205's performance, uptake, and litigation resilience remain to be evaluated across a broader set of geographies, project types, and political contexts.

In a growing number of jurisdictions, developers are deciding not to proceed because of either local process risk or the upfront cost and uncertainty of the state opt-in pathway. At the same time, the program's significance is not limited to the cases that actually enter the CEC docket. The very existence of a credible statewide alternative can strengthen a project proponent's position in negotiations with local governments by reducing the extent to which counties can assume that delay, burdensome conditions, or denial will leave the developer with no practical alternative. In that sense, AB 205 functions not only as a permitting pathway, but also as a negotiating lever. Some degree of centralization appears necessary to overcome local veto points at the scale implied by California's clean-energy mandates, yet AB 205 still stops short of a comprehensive delivery system. Persistent gaps in residual permits, real-property access, biological review, and schedule control limit its ability to translate state certification into built projects at the scale and pace required to meet the state's goals.

The recommendations offered here aim to convert AB 205 from a promising tool into a reliable engine for climate infrastructure. Implemented together, these reforms would maintain rigorous environmental and cultural safeguards while reducing uncertainty and delay. With these adjustments, California can better fulfill its clean-energy mandate, model effective governance for other jurisdictions and demonstrate that ambitious climate policy can be reconciled with accountability and environmental stewardship. More fundamentally, AB 205 addresses only one component of a multi-constraint system.

3 ILLINOIS



Public Act (PA) 102-1123 (originally House Bill 4412), signed into law on January 27, 2023, dramatically reshaped renewable energy siting in Illinois by overriding local bans and standardizing key requirements for wind and solar projects.[46] The law prohibits counties from enacting moratoria or outright bans on wind or solar development, mandating that all jurisdictions allow these projects subject only to "reasonable" standards. To enforce consistency statewide, the act set uniform siting standards that counties cannot exceed. For example, counties may limit wind turbine height only in line with the FAA's Determination of No Hazard for aviation.

Wind turbines must be set back at least 2.1 times their maximum blade-tip height from any occupied community building or non-participating residence, and 1.1 times their tip height from participating residences, public road rights-of-way, and non-participating property lines. Further, the law specifies that no component of a solar facility may exceed 20 feet above ground when the arrays are at full tilt. The required setbacks are 150 feet from any occupied community building or dwelling on a non-participating property, and 50 feet from non-participating property lines and public road rights-of-way. The law even specifies how to measure these distances to prevent misinterpretation, ensuring counties can no

46 Illinois Pub. Act 102-1123, 20 ILCS 5/5-222, et seq. (IL 2023).

longer impose stricter setbacks or heights than these state standards.

Beyond these siting standards, the law establishes uniform rules for operational impacts. Wind turbine shadow flicker is limited to 30 hours per year at any non-participating residence or other sensitive location. Noise levels must comply with the existing Illinois Pollution Control Board regulations, eliminating counties' ability to enforce any stricter noise limits than state environmental law provides. The law standardizes requirements on issues like ice throw sensors, turbine lighting, restoration of drainage tiles and soils, fencing, and vegetative ground cover, all areas where counties had previously imposed a patchwork of conditions.

The law addresses various ancillary aspects of project design and end-of-life obligations. Developers must enter Agricultural Impact Mitigation Agreements (AIMAs) administered by the Illinois Department of Agriculture to protect farmland during construction and operation. Developers must post financial security up to 100% of the expected removal cost minus salvage value to ensure funds are available for removal at the end of the project's life. The statute further narrows counties' ability to add certain extra financial-assurance or property-value-guarantee requirements beyond the state framework.[47]

The legislation imposes strict procedural timelines and milestones. Counties with an existing wind or solar siting ordinance must hold a public hearing within 45 days of receiving a complete application. That hearing conducted under Open Meetings Act transparency rules must be followed by a final county board vote within 30 days. In effect, once an application is deemed complete, a county decision is required within roughly 75 days, a major acceleration compared to the prior permitting regime, under which some counties dragged out decisions for months or even years.

Central to the reform is a "shall approve" provision. If a proposed wind or solar project meets all the standards set by PA 102-1123 and complies with relevant state and federal laws, the county must approve it. Discretionary denials on subjective grounds are no longer allowed, a significant departure from the previous county-by-county approach. To further deter obstruction, counties are barred from charging "unreasonable" application or permit fees. While the law does not define "unreasonable" in exact dollar terms, the intent is clear that fees should reflect only the actual administrative cost of processing the permit, not serve as a deterrent or hidden profit center.[48]

The law includes some grandfathering and exceptions to smooth the transition. Any application submitted before January 27, 2023, was evaluated under the old local rules, not the new statewide ones. Likewise, projects that had already submitted their AIMA to the Department of Agriculture before that date were exempt from the new siting standards. These clauses were important to avoid derailing projects already in progress and to prevent retroactive changes mid-stream. The statute defines a "commercial wind energy facility" as one with 500 kW or greater nameplate capacity, and defines "commercial solar energy facility" by reference to the Property Tax Code's definition of commercial solar energy system, focusing the framework on commercial-scale developments and leaving smaller installations to existing local rules. Finally,

47 Id.
48 Id.

counties that had renewable energy ordinances were required to amend them by May 30, 2023, to conform to the state law. This sparked a wave of ordinance updates across Illinois in spring 2023. Counties without existing ordinances weren't required to create new ones but must still follow state standards and timelines for new applications.[49]

Illinois later enacted the Clean and Reliable Grid Affordability (CRGA) Act, Public Act 104-0458, which Governor Pritzker signed on January 8, 2026 and which will take effect on June 1, 2026.[50] While CRGA serves in part as a legislative response to procedural implementation problems that emerged under PA 102-1123, it is a sweeping omnibus energy package that is designed to create a state dispute-resolution and siting-certificate pathway for certain facilities of 50 MW or greater, tighten local hearing timelines, establish more concrete fee benchmarks, extend the statewide siting framework to battery energy storage systems (BESS), address overlapping-jurisdiction conflicts, and limit unduly short construction-start deadlines.

This section therefore proceeds in three steps. It first examines the pre-reform landscape that led to PA 102-1123. It then analyzes the early implementation experience under PA 102-1123, including the recurring gaps and bottlenecks that helped spur enactment of CRGA. Finally, it assesses how far CRGA is likely to address those problems and identifies the issues that may remain even after the new law takes effect.

3.1 Pre-Reform Landscape

Prior to PA 102-1123, renewable energy development in Illinois encountered a fragmented and often unpredictable regulatory landscape dominated by county-level decision making. The reactions of local governments have been deeply shaped by Illinois' unique zoning and political history. Some residents and local officials perceive wind and solar facilities as delivering broader statewide benefits while concentrating land-use impacts locally. This framing was not uniform across rural Illinois, but it helps explain why renewable siting disputes became entangled with questions of local control, distributive fairness, and political representation.[51]

For local officials in many rural counties, zoning became a tool to assert control over decisions they experienced as imposed by state or urban-driven agendas. Zoning authority served both as protection for local landscapes and values and as a mechanism to block projects that some residents opposed, even when other neighbors supported them. In numerous cases, siting disputes divided communities: landowners who wanted to lease their land for renewable facilities found themselves at odds with neighbors who opposed development. For instance, counties like Jo Daviess and Carroll in northwest Illinois, which attracted educated urban residents and retirees drawn by scenic landscapes, enacted stringent wind ordinances to protect their vistas.[52] Many of these residents viewed large wind turbines as an unwelcome industrial intrusion, while many farming families saw turbines as compatible with agriculture and a source of supplemental income.

49 Id.
50 Clean and Reliable Grid Affordability Act, Pub. Act 104-0458 (IL 2026).
51 Shannon R. Anderson and McKenzie F. Johnson, "The spatial and scalar politics of a just energy transition in Illinois," Political Geography, Vol. 112 (2024).
52 Id.

Community opposition to wind farms first flared in the early 2000s during Illinois's initial wind boom.[53] After the state's first large wind facility came online in Lee County in 2004, dozens of projects followed, and more than 360 turbines were installed across north-central Illinois within a few years. This rapid development transformed rural landscapes and disrupted local governance procedures—many county governments were unprepared for energy facilities of this magnitude. In 2007, the state enacted PA 95-0203, setting some basic siting parameters for wind facilities but ultimately leaving implementation and final approval to county governments, preserving local control without addressing local capacity gaps. [54] Meanwhile, wind projects, spurred by federal incentives, were moving quickly, and some developers did not engage extensively with communities before construction. At the same time, by the late 2000s and early 2010s, organized opposition to wind energy was crystallizing in Illinois. Local and online networks of wind opponents formed, circulating claims about turbines' effects on health, scenery, and property values, some of which were inaccurate or exaggerated. This enduring infrastructure meant many counties faced well-coordinated resistance to any new project.

Counties responded in two ways: by imposing reactive restrictions after wind facilities were built or proactive restrictions to prevent future development. Of the 37 Illinois counties that eventually came to host wind turbines, 16 responded after the fact by enacting moratoria or very restrictive ordinances after turbines had already been constructed.[55] Meanwhile, in several other counties that had not yet attracted wind projects, officials proactively adopted strict siting rules or outright bans to preempt development. These measures were especially common in areas with many new ex-urban residents, people who had moved out from cities seeking a quieter rural lifestyle and who objected to the prospect of industrial-scale energy infrastructure in their adopted countryside.

Illinois governance has been described as a "Prairie Synthesis" of northeastern and southern influences.[56] Historically, Illinois counties could choose between a township form or a commission form of government—a structural distinction rooted in the state's nineteenth-century constitutional development and carried forward through later revisions—leading to a mosaic of local structures that persists to this day. Southern Illinois counties generally favored the conservative commission form, while many northern and central counties adopted township government. Adding to this diversity, the 1970 Illinois Constitution grants home-rule authority only to larger municipalities (over 25,000 people, or smaller ones if they affirmatively adopt it) and to counties with an elected chief executive officer (in practice, only Cook County). All other 101 counties are non-home-rule units that can exercise only the powers expressly given to them by state law.[57]

Illinois did not require counties to have zoning for unincorporated areas, and as of early 2023, around 78 of the 102 counties had county or local zoning ordinances for solar and/or wind, while 24 counties remained entirely unzoned.[58] In those unzoned counties, landowners

53 Id.
54 Id.
55 Id.
56 Id.
57 Ill. Const. 1970, art. 7, § 6
58 University of Michigan, "Energy Zoning," (accessed Mar. 2026), https://energyzoning.org/

historically had very few land-use restrictions. Property owners could use their land largely as they wished as long as they complied with baseline state and federal laws. Even in zoned counties, Illinois zoning traditions placed a strong emphasis on preserving the local rural character and protecting property values, often favoring the status quo. While some counties meticulously described plentiful application types, fees, compliance certificates, and other requirements, other counties required very little to engage in solar and wind development. In essence, prior to 2023 there was no uniform statewide approach to siting wind or solar; each county decided for itself whether and how to allow these projects, leading to a wide range of outcomes.

Another key turning point came with the passage of Illinois's Climate and Equitable Jobs Act (CEJA) in September 2021.[59] CEJA set ambitious goals: 100% clean energy by 2050 for the state, with interim targets like 40% renewables by 2030 and 50% by 2040. It expanded state programs to procure renewable energy credits for new wind and solar farms, ramped up incentives for community solar projects, and included equity provisions to ensure that benefits also flow to disadvantaged communities. CEJA set the stage for a substantial increase in renewable energy development to meet those targets. In response, local resistance intensified in parts of rural Illinois, and counties increasingly turned to moratoria, larger setbacks, and other restrictive measures.

59 Climate and Equitable Jobs Act, Pub. Act 102-0662 (IL 2021).

In late 2021 and into 2022, there was a wave of county-level actions.[60] Some counties enacted temporary moratoria on wind and/or solar projects, ostensibly to give them time to study the impacts, but effectively halting any projects for the duration. Others didn't ban projects outright but imposed new restrictive conditions that made it very hard to site a project. By 2022, at least 15 counties had adopted measures that effectively banned or significantly hindered construction.[61] The reasons cited for these local restrictions varied, but common themes included: protecting prime farmland from being taken out of crop production, preserving the scenic rural character, fears that nearby property values would decline, and even health and safety claims.[62]

FIGURE 3. Illinois Siting and Permitting Process[63]

By 2022, it became apparent to Governor Pritzker's administration and Democratic legislative leaders that the state would not meet CEJA's renewable energy targets if each county retained veto power or could impose years-long delays on projects. House Bill 4412 was approved by the Illinois General Assembly during the January lame duck session of the 102nd General Assembly.

60 Anderson and Johnson (2024)

61 "Support House Bill 4412: Siting Reform, Ratepayer Relief Essential to Climate & Equitable Jobs Act's (CEJA) Success" (Jan 2023).

62 Illinois State Association of Counties, "Wind and Solar Preemption – Legislative History" (Aug 2023).

63 For additional details about the ICC Expeditated Dispute Resolution process, see the "Recommendations" section below.

Rural county boards, the Illinois Farm Bureau and Illinois Association of County Board Members strongly opposed the bill, framing it as an erosion of local democracy and an imposition of urban will on rural communities.[64] They argued that it would mute community voices and force projects onto areas that didn't want them, all for the benefit of Chicago's power consumption.[65] Proponents, including renewable energy industry groups, environmental advocates, and most urban/suburban legislators, countered that local oppositions were preventing Illinois from reaching its climate commitments and attracting the private investment that comes with new energy infrastructure. In their view, giving every county a de facto veto was untenable when the state as a whole had decided to pursue a clean energy transition.[66] The outcome was the enactment of PA 102-1123, fundamentally shifting how wind and solar permitting works in Illinois.

3.2 Reform Early Outcomes

In the aftermath of PA 102-1123's enactment, counties responded in a variety of ways, and initial results are instructive. Some counties moved quickly to comply and even embraced the new framework.[67] For instance, counties that had existing wind or solar ordinances convened their boards and amended those ordinances by the May 2023 deadline to align with state law. Many counties simply copied the state's language verbatim, but a few took the opportunity to add supplemental local requirements within the statute's limits. White County, for example, updated its ordinance to include requirements for things like specific ground cover vegetation on solar facilities and detailed drainage restoration procedures, additional guidance that still fit within the state framework.[68] In effect, these counties signaled that, although the state had narrowed their discretion, they still intended to manage project fit through the remaining room for local implementation.

Other counties complied more narrowly and defensively. They adopted only the minimum standards required, passed symbolic anti-state resolutions, or sought to preserve some restrictive conditions as a signal of continued resistance. Champaign County had an illustrative case. Before they even formally changed their ordinance, their planning staff advised the board that the county's old large setback for solar facilities was now unenforceable under the new state law. As a result, when a pending solar project came up for approval in early 2023, the board approved it using the state's 150-foot setback rule even though the county ordinance hadn't yet been updated, effectively acknowledging that state law trumped the local rule on the books.[69] Finally, a handful of counties simply failed to meet the statutory compliance deadline and didn't update their ordinances by May 30, whether due to oversight, local political stalemate, or deliberate inaction.

64 Kay Shipman, "IFB opposes siting standards for renewable energy in lame duck," *Farm Week Now*, (Jan. 2023); Illinois State Association of Counties, "Wind and Solar Facility Resident Protection Act Support HB 3563/SB 2416" (Jan 2025); Michael T. Jurusik, "Public Acts 102-1123, 103-0081 and 103-0580—Overview of County Limitations on Regulation of Solar and Wind Energy Projects and Options for Legislative Amendments" (Jan 2024).

65 Illinois State Association of Counties, "Wind and Solar Preemption – Legislative History" (Aug 2023).

66 Dan Gearino, Aydali Campa, "Illinois Put a Stop to Local Governments' Ability to Kill Solar and Wind Projects. Will Other Midwestern States Follow?," *Inside Climate News*, (Feb. 2023)

67 Illinois State Association of Counties, "Wind and Solar Facility Law Task Force Survey Results Summary" (Apr 2024).

68 White County Board, "Ordinance No. 10-11-2023-14: Ordinance to Regulate Commercial Solar Energy Facilities," (Oct. 2023).

69 Champaign County Department of Planning and Zoning, "Preliminary Memorandum, Case 086-AT-23," (Mar. 2023).

Since the reform, Illinois has seen renewed wind and solar development under a faster permitting timeline, including several proposals that were previously stalled or denied under the old system. The Illinois Power Agency (IPA)'s procurement data reported a record amount of new renewable capacity over the last two years.[70] Solar development, in particular, has expanded across the state. PA 102-1123 likely contributed to that renewed momentum by reducing local siting risk, but it was not the only driver: procurement cycles, federal incentives, interconnection timing, and projects already in development also shaped the pace of new approvals.

Even with those caveats, one of the clearest early effects of the reform was renewed wind activity in Illinois. Prior to the siting reform, the state experienced a significant slowdown, entering what many in the industry referred to as a 4-year wind drought. Projects faced mounting local opposition, the proliferation of restrictive county ordinances, and lengthy, unpredictable permitting processes, as illustrated by cases like the canceled Pleasant Ridge Wind Farm in Livingston County in 2015.[71] The first two wind facilities secured final approval in Coles and McLean counties shortly after the new law took effect.[72] Subsequent approvals, such as the 200 MW Camp Creek I Wind Farm in McDonough County and projects moving forward in Ford and Menard counties, demonstrated that siting activity has revived. [73]

Before the reform, a county board's denial of a wind facility was typically the end of the road. Developers rarely legally challenged local governments because local zoning decisions were hard to overturn and it was often easier to just move on to a different location. After the reform, however, developers had a state mandate they could invoke in court if they believed a county was defying the law. Indeed, several high-profile lawsuits were filed to enforce the "shall approve" requirement. In Piatt County, for example, the county board initially voted down a wind project even though the developers argued it met all state criteria.[74] The developer signaled they would take legal action, and under pressure of likely losing in court, the county reconsidered and ended up approving the project. In Sangamon County, the developer similarly threatened to take legal action under the new law's provisions, which prompted the county to reverse its denial of the River Maple Solar project.[75]

70 Illinois Power Agency, "Renewable Resources," (accessed Mar. 2026).

71 Livingston County Board, "Denial of Special Use Permit for Pleasant Ridge Wind Farm," (Jul. 2015).

72 Coles County Board, "Approval of License Application for Coles Wind LLC," (2023); McLean County Board, "Resolution Approving Agreements for Wind Farm Projects," (Mar. 2023).

73 McDonough County Board, "Approval of Camp Creek I Wind Farm Project," (2023); Ford County Board of Commissioners, "Approval of Development Agreements for Pioneer Creek Wind Farm," (Nov. 2025); Menard County Board of Commissioners, "Wind Energy Siting Ordinance of Menard County," (Jul. 2023).

74 Piatt County Board, "Approval of Special Use Permit for Prosperity Wind Project," (Oct. 2023).

75 Sangamon County Board, "Denial of Conditional Permitted Use for River Maple Solar II," (May 2023); Sangamon County Board, "Resolution Granting a Conditional Permitted Use for River Maple Solar II," (Jul. 2023).

SOLAR SUCCESS STORIES

Grundy County's Buffalo Solar Farm (116 MW) provides a vivid case study of the impact of PA 102-1123. The County Board initially denied the project's special use permit in September 2023, following strong local opposition. Residents voiced concerns typical of pre-reform opposition, including the use of prime farmland, the visual impact on rural vistas, and uncertainties surrounding decommissioning. The vote to deny reflected deep divisions within the community, with some board members emphasizing landowner rights while others prioritized constituent objections. However, the passage of PA 102-1123 fundamentally shifted the legal landscape. Following the initial denial, the developer initiated a lawsuit against Grundy County. This legal pressure ultimately led to a settlement in March 2024, mandating the county to approve the project. The settlement included approximately 25 conditions beyond standard requirements, addressing local concerns through measures such as expanded setbacks, stormwater management, extensive landscaping to screen the panels, and detailed decommissioning security.[76] That broader dynamic in Grundy was later reinforced—and clarified more sharply—by appellate litigation. In Equity Solar Illinois v. County of Grundy, decided on March 10, 2026, the Third District held that the 2023 solar amendments substantially restricted a non-home-rule county's traditional zoning discretion with respect to commercial solar energy facilities. The court explained that while counties retain limited authority to impose statutorily permissible conditions, LaSalle/Sinclair-type compatibility review is not the governing framework for compliant CSEF applications, and once the applicant satisfies the authorized statutory and ordinance-based requirements, the county's role becomes sufficiently ministerial that mandamus may lie to compel issuance of the permit.[77]

Tazewell County's experience with multiple solar projects illustrates the new legal landscape under PA 102-1123. Initially, in May 2024, the County Board's Land Use Committee recommended denial for the Coyote Road Solar project (150 MW), citing concerns about farmland preservation and municipal growth areas, including objections from East Peoria officials. However, the full County Board reversed this decision in June 2024, approving the project. Several board members explicitly acknowledged that state law had effectively "tied their hands," citing potential legal exposure if they continued to deny a compliant application. Similarly, the Catmint Solar project, also facing local opposition and initial denials in May 2024, saw its denial reversed by the full County Board in June 2024 for the same reasons of legal risk under the new state law.[78]

Another illustration of the new legal framework emerged with the Unsicker Sun project. After the board's initial denial of this smaller solar project (approximately 5 MW) in August 2024, the developer filed suit in November 2024. In a subsequent settlement reached in March 2025, the project was approved. Board members publicly conceded that the county "went against state law" by denying the project.[79] This sequence of denials, lawsuits, and compelled approvals, driven by the constraints of PA 102-1123 and the threat of litigation, illustrates the shift in power dynamics from local discretion to state-mandated compliance in renewable energy siting.

76 Grundy County Board, "Agreement Reached for Buffalo Solar Project in Grundy County," (Mar. 2024).
77 Appellate Court of Illinois, Third District, "Equity Solar Illinois v. County of Grundy," (Mar. 2026).
78 Andi Anderson, "Tazewell county approves solar farm projects," *Illinois Ag Connection*, (June 2024).
79 Steve Stein, "Tazewell County Board changes course, approves five-megawatt solar farm near Morton," *WBCU*, (Mar. 2025).

Some counties have sought procedural workarounds without openly defying the statute. For example, despite the state law's mandate, the Will County Board repeatedly denied solar applications between 2023 and 2026, citing conflicts with the county's Land Resource Management Plan and strong local opposition.[80] By early 2026, these denials had generated at least five lawsuits. The County Board defended its decisions by asserting significant discretion over land-use compatibility, particularly concerning suburban growth areas.[81] Litigation and settlement continued as the primary enforcement pathway pending broader appellate clarification.[82] Meanwhile, Will County continued to approve solar projects in less contentious areas, demonstrating a selective approach to balancing renewable energy expansion with local land-use priorities.[83]

While this reform improved predictability for developers, it also fueled a sense of disenfranchisement in many rural areas, where residents felt their voices had been diminished. The shortened timelines, in some cases, made local debates even more acrimonious. Previously, a contentious project might involve months of back-and-forth, during which developers might make voluntary concessions or community agreements to win support. The law's timeline and "shall approve" language left less room for negotiation or delay. When boards approved projects because they believed state law left them little room to do otherwise, many residents felt ignored or sidelined, and local officials felt they bore the political cost for outcomes they no longer fully controlled. Illinois therefore remains a revealing test case of what happens when a state moves to standardize renewable energy permitting while leaving local governments to absorb much of the political fallout.

3.3 Identified Gaps and Bottlenecks

The first phase of implementation under PA 102-1123 revealed several recurring gaps and bottlenecks that prevented the process from operating as smoothly as the statute envisioned. Because CRGA had been enacted but had not yet taken effect as of this report's publication, these issues are best understood as the implementation failures that prompted the next round of reform. PA 102-1123 established a much-needed statewide baseline, no bans, consistent setbacks and noise limits, objective approval criteria, and clear timelines, but ambiguity in certain areas and uneven local follow-through created a new set of conflicts.

From the developers' perspective, the promised predictability of a uniform system was undermined by statutory ambiguities and residual gaps that allowed a partial patchwork to persist. Similar projects faced very different requirements from county to county because each county interpreted the statute differently. There was also a rise in new soft costs and hurdles that were not explicitly barred. For instance, some counties imposed flat application fees in the tens of thousands of dollars or required developers to post multi-million-dollar road bonds and liability insurance in the nine-figure range for even small commercial solar projects, costs that could undermine project economics, especially for smaller developers.

80 Michelle Mullins, "Will County Board rejects solar facilities near New Lenox, Wilmington," *Chicago Tribune*, (May 2025)

81 *LaSalle National Bank v. County of Cook* and *Sinclair Pipe Line Co. v. Village of Richton Park* are two Illinois Supreme Court cases that established the key factors used to determine the validity of zoning ordinances.

82 Circuit Court of the Twelfth Judicial Circuit, Will County, Illinois, "Complaint for Declaratory Judgment and Injunctive Relief," (2025).

83 Will County Board, "Resolution Approving Special Use Permits for Solar Energy Facilities," (2024).

Tactics to slow the timeline also emerged despite the statutory clock. Common examples included: disputes over when an application was complete, stretching public hearings over several nights to buy time, and waiting months after zoning approval to issue secondary permits like building permits. The law did not establish a fast-track appeal to a state body for these situations, meaning that if a developer believed a county was uncooperative or adding more restrictive conditions, the only remedy was to sue in court—an option many smaller developers could not afford, which undercut the law's intent.

County officials, on the other hand, had their own mirror-image frustrations. Many emphasized that they had no input in passing the law. They acknowledged that outright bans were no longer allowed and that state standards set clear boundaries, but because the law failed to define some of its key terms like "more restrictive," they were uncertain how they could review a project to meet local conditions without violating the law. For example, could they impose conditions beyond the state minimum if they could argue it's for public welfare, or is anything beyond the state floor automatically illegal? The statute is silent on this, leaving counties guessing and potentially exposed legally if they guessed wrong.

County officials also noted that while they still performed all the procedural work—issuing notices, holding hearings, making a record, issuing subsequent permits, handling road agreements, drainage issues, and similar tasks—they felt they had far less actual influence over the outcome. There was a palpable sentiment that they were tasked with implementing state energy policy but were not given full authority or support to manage the consequences, and they feared being sued if they stepped out of line. Several county boards said they felt placed in an untenable position by the state. If they approved a project, angry residents blamed them; if they denied one, the developer would initiate litigation.

Public hearings under the new law thus became high-conflict venues. Counties were required to hold a hearing for each project, and residents came expecting to express their concerns. However, much of what community members wanted to discuss was no longer a legally valid reason to modify or deny a project under the state's criteria. As a result, there was often a perception that the process was performative and that community concerns were ignored. Meanwhile, county board members sat through hours of testimony while recognizing that, unless someone presented evidence that a project failed to meet one of the objective standards, they could not lawfully deny the project. They sometimes tried to ask the developer for concessions, but the developer was equally aware of the legal framework. If the proposed facility met the requirements, the developer did not have to agree to anything further. Accordingly, local elected officials ended up absorbing the political cost for project approvals that they felt the state had compelled them to approve.

Both viewpoints had some merit. Counties often felt they had been left to administer a process they no longer meaningfully controlled, while developers felt some counties continued to place obstacles in their path. The 2023 reform has left structural holes that neither developers nor counties could fully address on their own. Some of the major gaps that have emerged include:

Ambiguity in the Statute: The ambiguity in the law has led to confusion over procedure. The law doesn't define "more restrictive," leaving open the question of whether any added county condition is illegal, or would only be so if it directly contradicts a state standard. Likewise, “reasonable” fees or requirements aren’t defined, so counties err on the side of charging higher amounts to cover all contingencies, while developers complain that “reasonable” has been exceeded. Nor does it explicitly state whether the traditional discretionary criteria that counties use for special-use permits, which are often derived from Illinois court cases like LaSalle or Sinclair, still apply in evaluating a wind or solar project. In Illinois zoning, typically even if something is a permitted special use, the county board weighs factors about the project’s harmony with the comprehensive plan, its effect on adjacent property, public health and safety, etc.

Many counties continued to recite those factors in their findings for solar and wind projects. Developers argued that doing so was beyond the county’s authority, asserting that if they met the objective state standards, the project must be approved regardless of subjective factors like community character. Additionally, by not addressing certain topics like drainage, floodplains, or co-location of battery storage, the statute leaves ambiguities that resulted in friction in nearly every application. Every new project became a test case about what would constitute as a complete application, what conditions were permissible, and whether those old discretionary standards could still play a role.

For commercial solar applications, that issue is now materially clearer. In Equity Solar Illinois v. County of Grundy, the Third District held that the discretion preserved by section 5-12020 is limited to conditions authorized by the statute and that broader LaSalle/Sinclair-style compatibility analysis is inapplicable where the application otherwise satisfies the governing statutory and ordinance requirements. That decision substantially narrows one of the most important ambiguities discussed here. Even so, questions may still remain in adjacent contexts, including the treatment of wind facilities, storage, overlapping permitting layers, downstream approvals, and the implementation of CRGA’s newer procedures.

Incomplete Preemption and Overlapping Jurisdictions: While the reform aimed to standardize permitting, some counties adapted by using procedural and financial tactics to regain leverage. For instance, some township highway commissioners asked for exorbitant road use fees, in one case, on the order of a million dollars, as a condition to let turbine components use their roads. Unable to outright ban renewable facilities, some counties imposed costly requirements, such as evergreen tree buffers or high bonds, which could make projects economically unviable. As application fees faced increased scrutiny, some counties adapted by mandating excessively high insurance coverage or alternative financial guarantees instead. Counties like Grundy, Livingston, Logan, Will, McHenry, and Coles have very onerous pre-application and hearing processes even after the law—requirements like months-long checklists, multiple rounds of review before even accepting the application.[84] In some other counties, the final decision hinged not so much on whether wind or solar was allowed in general, but on whether local politics could build a record to reject a particular project despite the state criteria.

84 Livingston County Board, “Livingston County Code Article VIII: Commercial Wind and Solar Energy Facilities, Section 56-616 (Siting Approval Application),” (Amended Feb. 2024); McHenry County Board, “Unified Development Ordinance: Zoning Application Process and Completeness Review,” (2022); Grundy County Board, “Ordinance No. 4071: Regulations for Solar and Wind Energy Systems,” (2023); Will County Land Use Department, “Commercial Land Use and Special Use Permit Application Guidelines,” (2024); CPV Prairie Dock Solar, “Special Use Permit Application Narrative,” Livingston County, (Oct. 2024).

Multiple Jurisdictions = More Delays: Illinois' system of counties, townships, municipalities with a 1.5-mile extraterritorial jurisdiction (ETJ) zone, and other entities like drainage districts means a project could be subject to overlapping approvals or objections. The state siting law didn't fully clarify how a wind or solar project near a town or spanning county lines should be managed. As a result, a municipality near a proposed wind facility could assert its ETJ to effectively forbid turbines unless the power is used on-site, or villages could demand pre-annexation agreements from developers. Private drainage districts, which control drainage infrastructure, emerged at late stages claiming a project would harm their drains, causing further delay until agreements were reached or lawsuits threatened. If a project crosses from one county into another or into a township with separate zoning, sometimes multiple sets of hearings happened, possibly with inconsistent outcomes.

One concrete example is *Hickory Wind LLC v. Village of Cedar Point*, decided by an Illinois appellate court on August 1, 2025.[85] In that case, a small village tried to use its zoning power in the 1.5-mile ETJ ring around its boundaries to say that any commercial wind turbine in that zone could only be built if it was for on-site consumption. The appellate court reversed summary judgment for the village and invalidated the ordinance, holding in substance that the village had exceeded its lawful authority by using its zoning power in that exclusionary way. However, the decision confirms that municipalities may continue to test the edges of their authority, but it also makes clear that outright prohibitions disguised as regulation are vulnerable to being overturned. The continuing risk is therefore less a durable municipal veto than episodic delay, expense, and forum-shifting when local governments press restrictions that exceed their statutory authority.

Enforcement and Conflict Resolution Void: The law lacks a conflict resolution mechanism to enforce its requirements and resolve disputes besides the judicial system. Therefore, if a county is imposing an arguably illegal condition or dragging its feet, the only option is for developers to file a lawsuit in circuit court. Court cases are slow and costly for all parties. Further, taking legal action against a county could damage the developer's relationship with that community going forward. Most developers preferred not to litigate against a county where they planned to operate for 30 years, so they often tolerated some delays or extra costs rather than litigating every issue. Counties were aware of this reluctance, and a few treated permits almost like bargaining chips, sometimes adding last-minute conditions or fees in the expectation that the developer would comply rather than resort to a lawsuit. Once one developer agreed to these terms, they could become the expected norm, and the county would likely use that as a basis for increasing fees and tightening requirements moving forward. In essence, "compliant projects shall be approved" is a powerful phrase on paper, but without a speedy enforcement mechanism, it does not always prevent gamesmanship in practice.

Mismatch Between Federal, State and Local Approvals: Environmental, biological assessments, species consultations, cultural and tribal resource consultations, and any other federal, state, and local agency action or decision facilitating the development, construction, or operation of wind or solar energy facilities are not centralized. The current process often involves a zoning approval first, then subsequent permits like building permits, environmental

85 *Hickory Wind, LLC v. Village of Cedar Point*, IL App (3d) 240513 (Aug. 2025)

permits, etc. A developer might submit extensive documentation to one of the involved agencies, but then a county might separately ask for similar info or additional studies. These consultations are usually taking place on a separate track for years that often isn't even finished by the time the county issues an approval, which can cause confusion about whether construction can start or can lead to major modifications to an approved project.

Lack of Implementation Tools: When the law passed, there was no accompanying implementation guide or resources for counties to draw upon. No model ordinance was provided, no standard checklist for what an application should include, no example road use agreement balancing developer and county needs, no training workshops offered by the state on how to handle the new process. Some counties have very professional planning departments and attorneys who developed their own forms and processes consistent with the new law. Others, especially those with few staff or no prior wind and solar experience, have struggled.

Capacity Constraints: Many of Illinois' rural counties have very limited staffing, perhaps one zoning officer or part-time consultant, and certainly no in-house engineers or environmental experts. The new law's compressed timeline is increasingly challenging for them. These capacity issues can lead to delays and extra hurdles, simply because the counties are not equipped with resources to efficiently process the applications within the tight timeframe the law envisions.

Mismatch Between Project Scale and Process: One particularly glaring inefficiency is how community solar projects are being put through almost the same permitting process as utility-scale projects. These smaller projects still require full special use hearings, extensive studies, large application fees, etc. There are multiple cases where community solar developers obtained their permits, but then because of interconnection delays, the permits actually expired before the project could get built. This forced the developer to start over with a new application and hearing for essentially the same project, adding cost and uncertainty, even though nothing materially had changed except the calendar.

Erosion of Trust and Cooperative Spirit: Perhaps the most important issue is the deterioration of trust and collaboration between developers and counties. Before the 2023 reform, as contentious as issues could get, there was often a negotiation phase; developers would work with counties and communities to find middle ground to obtain a permit. After the reform, developers felt they had a legal right to approval if they met the standards, and some approached development with a more legalistic posture. Counties, for their part, were feeling a loss of control, sometimes reacted defensively and used every available procedural lever to assert themselves. The trust that is needed for a decades-long project to operate smoothly in a community is being frayed at the very start. This adversarial undertone undermined the ability to collaboratively address much needed project- and site-specific issues.

PA 102-1123 has transformed many of the most egregious local barriers, which now show up as: (1) stretching "completeness" to delay starting the clock; (2) marathon hearings; (3) excessive road use demands; (4) high permit fees; (5) ornamental screening; and (6) municipal ETJ or pre-annexation gambits in the 1.5 mile belt to re-impose stricter rules.   These patterns recurred across multiple counties during the first phase of implementation and help explain the policy logic of CRGA. Even so, some of them—especially disputes over application completeness, downstream permits, insurance and bonding demands, and smaller-project enforcement—may persist unless the new statute is implemented with clear rules and adequate administrative capacity.

3.4 Recommendations

PA 102-1123 eliminated the most visible barrier to renewable energy siting in Illinois—county bans and highly inconsistent baseline standards—but it did not eliminate local leverage. As the previous section shows, the resulting system was more uniform on paper than in practice. CRGA is a significant legislative response to several of the most visible implementation problems that emerged under PA 102-1123, but as of this report's publication it had been enacted, not yet implemented. The discussion below therefore identifies the principal ways the new law is designed to strengthen the framework and then highlights the structural gaps that may remain once it takes effect.

Create a State-level Enforcement Backstop: CRGA is designed to respond to one of the clearest weaknesses in PA 102-1123 by creating a state override pathway for facilities of 50 MW or greater. Under the prior framework, a developer facing an unlawful denial or an effectively obstructive local process often had only one practical remedy: filing suit in circuit court. CRGA is designed to partially address that problem by authorizing the Illinois Commerce Commission (ICC) to resolve qualifying siting disputes and, in specified circumstances, issue a siting certificate for a compliant facility. The statute establishes an expedited procedural schedule, beginning with a required notice-and-cure opportunity and proceeding through petition, rapid pleadings, an administrative hearing, and a final ICC order on compressed timelines. This change would be significant because it would provide a more formal enforcement mechanism and reduce the likelihood that a large project can be blocked simply by forcing the developer into lengthy, expensive litigation.

Tighten Local Timelines to Reduce Procedural Delay: CRGA is further designed to respond to the delay-by-procedure problem by tightening the local review timeline. PA 102-1123 imposed deadlines once an application was deemed complete, but experience under the law showed that counties could still stretch the process through hearing schedules, continuances, or disputes over timing. CRGA is intended to reduce that flexibility by requiring the hearing process to conclude within 60 days and the final vote to occur within 30 days thereafter. Importantly, the amended statute uses "conclude" rather than merely "hold" for the 60-day hearing requirement, a distinction designed to prevent counties from satisfying the letter of the deadline by opening a hearing within the window while continuing it indefinitely. In doing so, it attempts to make the statutory timeline more operational and less susceptible to incremental procedural drift.

Constrain Fee-Based Obstruction: One of the most persistent implementation problems under PA 102-1123 was the statute's reliance on vague standards such as "unreasonable" fees, which invited case-by-case disagreement and encouraged some counties to test the outer limits of cost recovery. CRGA narrows that ambiguity by establishing more concrete fee benchmarks, including per-megawatt ceilings for certain application fees and county building-permit fees for wind and solar facilities. This reform is meant to reduce the use of fees as a deterrent while still preserving room for legitimate administrative cost recovery.

Extend Statewide Framework to Storage and Overlapping-jurisdiction Problems: CRGA is designed to address gaps in coverage and overlapping-jurisdiction issues that PA 102-1123 left only partially resolved. By explicitly bringing battery energy storage systems into the statewide siting framework, CRGA extends the preemption logic beyond wind and solar and attempts to prevent storage from becoming the next site of fragmented local regulation. It also addresses certain multi-jurisdiction and extraterritorial conflicts by limiting some municipal veto dynamics and creating tools for more consolidated treatment of projects that span multiple local boundaries. In that sense, CRGA reflects an effort to reduce the number of parallel local processes that can function as de facto delay.

Reduce Post-Approval Instability: CRGA is designed to address post-approval instability by limiting the use of short construction-start deadlines that can effectively nullify an approval before a project is financeable or buildable. Experience under the earlier framework showed that projects often face multi-year interconnection, equipment, financing, and procurement timelines that do not fit traditional local zoning assumptions. By prohibiting construction-start deadlines shorter than five years for wind and solar facilities and at least three years for energy storage approvals, CRGA attempts to align the siting process more closely with the actual development timeline of modern energy projects.

Taken together, these reforms show that lawmakers recognized many of the same implementation problems identified in this report and attempted to close several of the most visible loopholes. However, CRGA should still be understood as an important but partial response rather than a complete solution. The more useful question at this stage is whether the statute, as enacted, appears well calibrated to the implementation failures revealed under PA 102-1123 and where additional reform may still be needed. For example, the ICC backstop applies only to facilities at or above 50 MW, leaving many smaller solar and community-scale projects within the original county-centered system, where litigation remains the primary enforcement tool. Timeline tightening does not fully eliminate disputes over application completeness or downstream approvals. While fee caps may reduce one form of cost leverage, other pressure points—insurance demands, road-use conditions, bonding methodologies, drainage disputes, and post-approval permitting—can still serve similar functions unless they are constrained by clearer standards and more uniform implementation tools.

3.5 Conclusion

Illinois' 2023 siting reform materially changed the renewable energy permitting landscape. Combined with favorable federal incentives and market conditions, PA 102-1123 accelerated approvals, especially for solar, and reopened jurisdictions that had previously attempted to block or delay utility-scale development. It replaced a highly fragmented system with statewide baseline standards, statutory decision timelines, and a stronger presumption that compliant projects should move forward.

PA 102-1123 succeeded in eliminating outright bans, but it did not produce a uniformly stable or politically sustainable siting process. It addressed a problem concentrated in a relatively small number of counties, yet it did so through a statewide rule that generated resentment well beyond those jurisdictions. In many counties that had not been the principal source of obstruction, local officials were left with bad will because they felt stripped of discretion and excluded from the design of the reform. In the counties that had been most hostile, opposition often adapted rather than disappeared, shifting into process, price, and downstream leverage.

The state, counties, and developers are now caught in a dysfunctional triangle of shifted burdens and mismatched accountabilities. County officials remain politically exposed, tasked with administering and often approving projects under state mandate while absorbing constituent anger for decisions they do not fully control. Many approvals became, in effect, a qualified “yes”: a formal approval accompanied by continuing disputes over conditions, costs, or subsequent permits.

CRGA reflects legislative recognition that PA 102-1123’s first-round reforms did not fully solve the operational problems that surfaced in practice. In several respects, CRGA adopts the kinds of fixes this report identifies as necessary: a stronger enforcement pathway for certain larger projects, tighter procedural deadlines, clearer fee benchmarks, broader coverage for storage, and some limits on overlapping local leverage. However, CRGA’s real-world success remains to be tested. Closing one avenue of obstruction may simply redirect conflict into the next available gap—completeness disputes, downstream permits, fee and bonding demands, or judicial review of contested state decisions.

The long-term question is not only whether Illinois can keep projects moving, but whether the state can build a siting framework that is predictably enforceable, administratively workable, and publicly legitimate. That will likely require more than successive rounds of partial preemption aimed at the most visible failure points. Illinois’ experience illustrates both the promise and the limits of state-level siting reform. Preemption can restart stalled investment and reduce the most visible forms of local veto. However, preemption without precision invites adaptation, uniformity without implementation capacity produces uneven results, and faster timelines without durable governance tools can shift conflict rather than resolve it. Unless the remaining leverage points are addressed more comprehensively, Illinois may continue to experience a cycle of bottleneck closure and workaround substitution rather than achieving a fully stabilized siting regime.

4 NEW YORK

New York's journey toward a decarbonized electricity system is marked by an uneasy convergence of local land-use authority and a long history of state intervention in energy siting. Although municipalities have traditionally exercised substantial control over zoning and development, New York has repeatedly centralized approval of major energy facilities through statewide siting regimes.

In the early 2000s, New York began to introduce policy frameworks to encourage renewable energy. By the late 2010s, New York's renewable generation mix was still heavily shaped by legacy hydropower, while wind and solar remained a much smaller share of statewide electricity supply. At the same time, a substantial portion of the state's zero-emission electricity came from nuclear plants, several of which faced retirement pressure. Meeting rising demand while replacing aging zero-emission and fossil generation would therefore require a massive build-out of wind, solar, and storage, along with new high-voltage transmission infrastructure to deliver electricity from rural generation hubs to urban load centers. This need for land-intensive projects collided with rural landscapes, raised concerns about natural and cultural resources, and invoked deep questions about community identity. The Climate Leadership and Community

Protection Act (CLCPA), enacted on July 18, 2019, transformed the state's decarbonization from a policy preference into a legal mandate by requiring that 70% of electricity be generated from renewable sources by 2030 and that the entire supply be emissions-free by 2040.[86] The state faced a fixed timetable in which dozens of large-scale renewable energy projects had to be approved and built within a decade or two.

This combination of localism and statutory urgency created tensions that permeate every aspect of the siting debate. Communities often view renewable projects as industrial intrusions that benefit outside entities and the state at large but impose burdens locally. Visual impact, noise, temporary construction disruptions, and potential effects on property values become primary concerns of opposition. Yet the benefits—clean air, reduced greenhouse-gas emissions, new jobs, grid reliability, and economic opportunities such as tax payments or lease income—are diffuse and sometimes intangible to rural residents. The CLCPA's binding mandates established that deferring or relocating a project in a community could shift those burdens to another community or risk shortfalls in generation and reliability. Thus, the central question turned from whether renewable energy projects should exist to how and where they could be sited in a way that honors community and environmental concerns while meeting statewide decarbonization goals.

By 2026, however, that timetable became not only a legal imperative but also an economic, infrastructural, and political implementation challenge. Public debate had widened beyond permitting speed to include affordability, rate impacts, transmission and interconnection constraints, procurement uncertainty, federal funding instability, and continuing local disputes over particular renewable and storage projects.[87] The siting debate therefore no longer turns only on administrative efficiency or on how far the state may go in accelerating renewable deployment over local objection. It also turns on whether approved projects can be financed, built, and interconnected on a timetable and at a cost that remain politically sustainable in a home-rule state.

4.1 Pre-Reform Landscape

Efforts to centralize power-plant siting predate the renewable era. In 1972, New York enacted Public Service Law Article VIII, creating a one-stop siting process for major steam-electric facilities and vesting exclusive authority in a state Siting Board to issue a Certificate of Environmental Compatibility and Public Need.[88] Article VIII allowed preemption of local requirements in certain circumstances, but its procedures provided more limited public participation than later regimes, and it ultimately sunset on January 1, 1989.

The legislature did not replace Article VIII until 1992, when it enacted Public Service Law Article X. Article X expanded the statewide licensing model, raised the applicability threshold from 50 MW to 80 MW, and increased opportunities for public and municipal participation, including an

86 Climate Leadership and Community Protection Act, S. 6599 (NY 2019); Accelerated Renewable Energy Growth and Community Benefit Act, N.Y. Laws ch. 58, Part JJJ. (NY 2020)

87 Diana DiGangi, "New York Needs More Time to Meet Climate Goals, Gov. Hochul Says," *Utility Dive* (Mar. 2026).

88 Public Service Law Article VIII (NY 1972); G.S. Peter Bergen, "Electric Generating Facility Siting and Licensing in New York State's Restructured Electric Utility Industry," Environmental Law in New York, Vol. 10 No. 7 (July 1999).

intervenor account funded by applicant deposits.[89] Article X itself sunset on January 1, 2003, when the legislature did not renew it. For over seven years there was no comprehensive state siting statute covering new power plants. During this hiatus, wind and solar projects were left to navigate the patchwork of local land-use laws and state permits. Towns exercised land-use control, requiring special use permits, variances or zoning amendments for new development. The mid-2000s saw significant wind deployment; more than 1,200 MW of wind capacity was built across upstate New York during the Article X hiatus.[90] Projects such as Maple Ridge Wind Farm and Noble Bliss Windpark were constructed by working closely with local governments and offering financial benefits to host communities.[91] Developers generally chose sites where community support was strong or where the economic benefits of hosting turbines outweighed concerns about aesthetics and noise.

However, the absence of a centralized state framework revealed systemic weaknesses as renewable proposals multiplied. Each project required separate approvals from multiple towns, counties, and state agencies, all operating on different timelines. Developers had to secure special use permits or variances from town planning boards, complete the State Environmental Quality Review Act (SEQRA) reviews often led by local agencies, and obtain state permits for wetlands and wildlife impacts. Projects that spanned multiple municipalities faced inconsistent setbacks, height limits and road use rules, forcing developers to design projects to satisfy the most restrictive requirements. [92] Some towns imposed moratoria on wind development to rewrite their zoning laws and ordinances. Others enacted zoning amendments that effectively banned commercial wind projects by, for example, establishing turbine height limits or requiring setbacks of more than a mile from property lines. These measures created patchwork restrictions that were difficult for developers to navigate and increasingly unpredictable for financiers.

SEQRA, intended to ensure that environmental impacts were thoroughly considered, became a forum for prolonged debates over aesthetics, wildlife impacts, and socioeconomic concerns. Opponents used SEQRA to demand detailed visual simulations and noise studies, raising questions about property values and quality of life. Because SEQRA has no firm deadlines, the process could stretch for years. Even supportive towns struggled with the complexity of large-scale renewable projects and the need to coordinate with state agencies. Uncertain timelines deterred some developers from pursuing projects in New York, especially as neighboring states offered more streamlined paths.[93]

Recognizing that the patchwork system was too slow and unpredictable to support a large-scale renewable build-out, the legislature enacted Public Service Law Article 10 (Article 10) in 2011.[94] This statute reinstated a centralized Siting Board to review and authorize electric generating facilities of 25 MW or more. Article 10 included renewable projects within its scope and reintroduced intervenor funding. The process required developers to file a Public

89 Bergen (1999)

90 Jim Muscato & Jessica Ansert Klami, "New York May Finally Have a Renewable Energy Siting Process to Achieve Its Aggressive Climate Action Goals" (July 2020).

91 Avangrid, "Maple Ridge Wind Farm Celebrates Clean Energy for the Empire State," (Sep. 2006); New York Department of Public Service, "Noble Bliss Windpark, LLC," 06-00135/06-E-0135 (accessed Mar. 2026).

92 State Environmental Quality Review Act, N.Y. Envtl. Conserv. Law § 8-0101 et seq. (NY 1975).

93 Muscato and Klami, "New York May Finally Have a Renewable Energy Siting Process to Achieve Its Aggressive Climate Action Goals"

94 Public Service Law Article 10, N.Y. Pub. Serv. Law §§ 160–173. (NY 2011)

Involvement Program plan to outline how they would engage communities and stakeholders early in the process. Applicants also had to negotiate with state agencies in a stipulation phase to agree on study methodologies for wetland delineations, wildlife surveys, noise modelling, visual impact assessments, and cultural resource investigations. Once an application was deemed complete, the Siting Board was required to issue a decision within twelve months.

Article 10 provided a complex and litigation-like process. Applicants had to prepare voluminous filings, sometimes numbering tens of thousands of pages, to satisfy the requirements of multiple agencies. The stipulation phase, intended to settle the scope of studies, often turned into protracted negotiations. If parties could not reach stipulations, the applicant had to complete all potential studies to satisfy each agency's preferences. After filing, the Department of Public Service (DPS) and other state agency staff would review the application for completeness and frequently issued deficiency letters requiring additional information before the clock started. Once complete, the application entered a quasi-judicial phase in which parties filed direct and rebuttal testimony, cross-examined witnesses, and submitted briefs. The Siting Board could waive local laws only if compliance was unreasonably burdensome due to technological infeasibility or cost. The Siting Board's final decisions had to be supported by a comprehensive record addressing environmental, social, economic and technical considerations.[95]

Despite the formal goal of a twelve-month decision timeline, Article 10 proceedings for renewable projects often lasted much longer. By early 2020, nearly nine years after Article 10's enactment, only a handful of renewable projects had secured certificates, and none had begun operation. One wind project spent eight years in the Article 10 pipeline before receiving a certificate, rendering its commercial offtake agreement obsolete.[96] Developers grew reluctant to enter the process, sometimes limiting projects to under 25 MW to avoid Article 10 altogether. The combination of lengthy pre-application requirements, extensive hearing procedures and uncertainty around local law waivers created a system that was thorough but not timely.[97]

The climate imperative and the deficiencies of Article 10 spurred lawmakers to enact the Accelerated Renewable Energy Growth and Community Benefit Act (Act) as part of the state budget in April 2020.[98] Central to the Act was Executive Law § 94-c, which established the Office of Renewable Energy Siting and Electric Transmission (ORES or Office) as the nation's first state agency dedicated exclusively to permitting large-scale renewable generation and co-located energy storage projects. The statute created a new one-stop permitting process that replaced Article 10 for renewable projects and set explicit deadlines. The creation of ORES marked a recognition that the decarbonization timeline required a dedicated, professionalized permitting body able to issue timely decisions while upholding rigorous standards.

Projects with a capacity of 25 MW or greater (and those between 20 and 25 MW that opt in) apply to ORES for a consolidated siting permit that centralizes the principal siting decision and displaces many otherwise applicable local permits and state approvals. In practice, however, projects may still need certain non-duplicative federal, federally delegated, and local

95 Muscato and Klami, "New York May Finally Have a Renewable Energy Siting Process to Achieve Its Aggressive Climate Action Goals".
96 Michael B. Gerrard and Edward McTiernan, "New York's New Statute on Siting Renewable Energy Facilities," (May 2020).
97 Cullen Howe, "Breaking Down the Barriers to Siting Renewable Energy in New York State" (n.d.).
98 Accelerated Renewable Energy Growth and Community Benefit Act (NY 2020)

approvals outside the ORES permit. Those residual approvals can include matters such as the New York State Public Service Commission (PSC) police-power approvals, the New York State Department of Transportation permits, and local fire or building code implementation.

ORES must determine whether an application is complete within sixty days, and once complete, the office has one year to issue a final decision (six months for projects on previously disturbed sites like brownfields or landfills). If ORES fails to provide notice of its determination of completeness or incompleteness within the required timeframe, the application is deemed complete. Draft permits with proposed uniform and site-specific conditions must be published for at least sixty days of public comment. Adjudicatory hearings are held only for issues deemed "substantive and significant," thus narrowing the scope of litigation. If ORES fails to make a decision by the statutory deadline, the draft permit conditions automatically will become final.

The Act acknowledged that without streamlined siting, New York would not meet its CLCPA targets. Yet the statute also sought to maintain environmental protections and public participation. Local governments retained the right to comment and raise objections, and ORES was directed to consider all substantive comments when crafting final conditions. The Act further created a Host Community Benefit Program, whereby residents in communities hosting large-scale renewable projects receive utility-bill credits or discounts funded by developers; as implemented, the program requires annual payments of $500 per MW for solar facilities and $1,000 per MW for wind facilities during the first ten years of operation. Intervenor funds continued to support local participation, and the statute emphasized that expediting the process should not compromise environmental integrity or procedural fairness.

In April 2024, the state passed the Renewable Action through Project Interconnection and Deployment Act (RAPID Act), which transferred ORES from the Department of State to DPS. The Act recodified the major renewable energy siting program into Public Service Law § 3-c and a new Article VIII.[99] The recodification transferred existing ORES regulations from Title 19 Part 900 of the New York Codes, Rules and Regulations to Part 1100 under Title 16, aligning the renewable siting program with the broader public service regulatory framework. The RAPID Act authorized DPS to oversee both major renewable generation and major electric transmission projects, with Article VIII covering major electric transmission facilities that are 125 kV or more extending at least one mile, or 100 kV to under 125 kV extending at least ten miles. Final regulations implementing new Article VIII—16 NYCRR Parts 1100, 1101, and 1102—were approved by NYPSC on February 12, 2026, and took effect on March 9, 2026. The succeeding sections will examine the early outcomes of the ORES reform, the gaps identified in its implementation, and recommendations for further improvement.

4.2 Reform Early Outcomes

When Executive Law § 94-c took effect on April 3, 2020, ORES was tasked with building a new agency from scratch—recruiting staff, developing regulations and coordinating with sister agencies—while processing applications immediately, even before its permanent regulations

99 Renewable Action through Project Interconnection and Deployment Act, A08808-A (NY 2024).

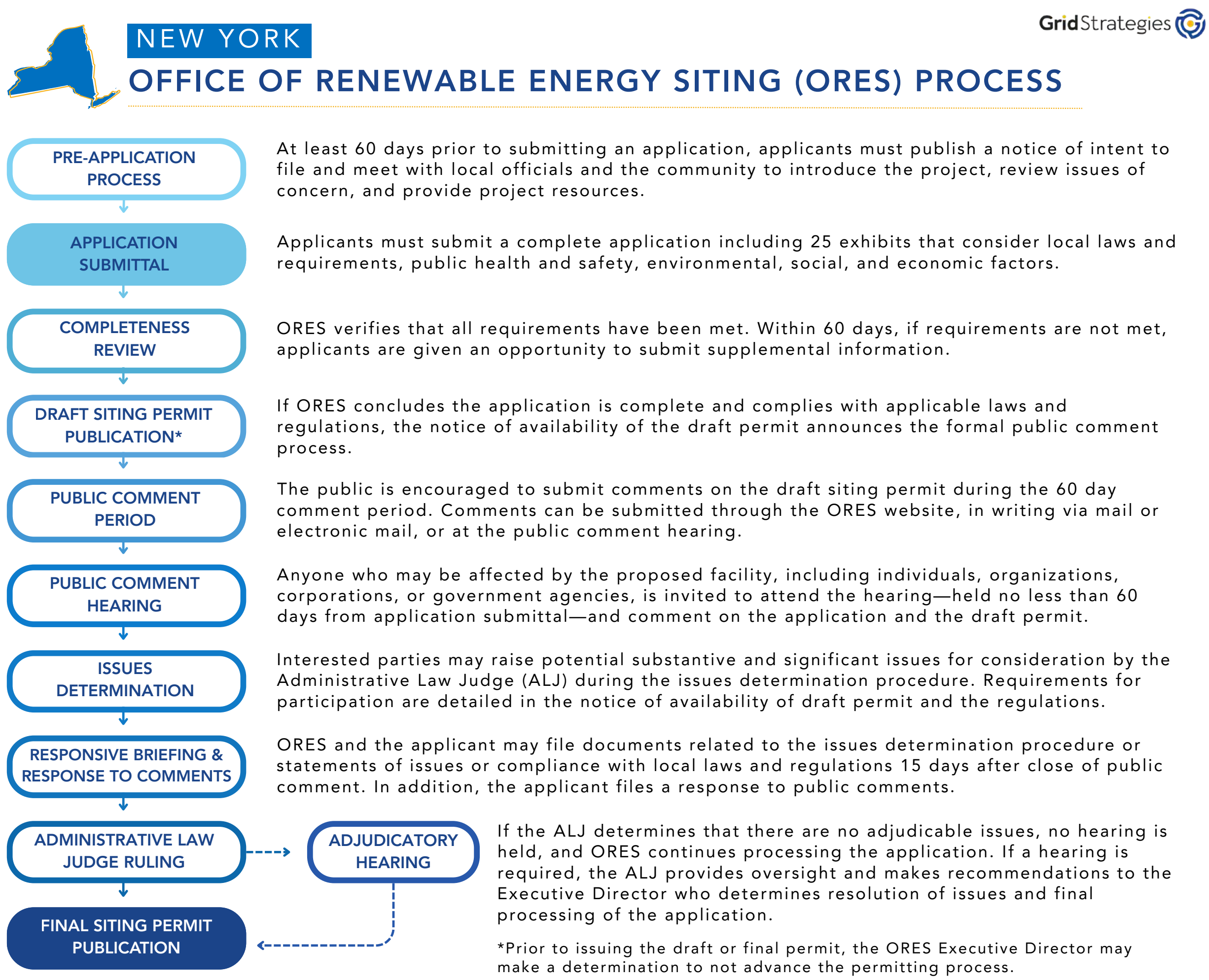
and uniform standards were in place. Within weeks, dozens of developers transferred their in-progress Article 10 applications to ORES, recognizing that the new process offered a clearer timeline and avoided the drawn-out stipulation phase. Simultaneously, developers who had been preparing projects under the local route or who had been waiting for Article 10 to improve now filed transferred applications directly with ORES.

ORES adopted its regulations including uniform standards and conditions (USCs) in less than a year after extensive stakeholder engagement.[100] The regulations set baseline requirements for major siting impacts such as noise, shadow flicker, setbacks, height, wildlife and wetland protection, agricultural mitigation, and decommissioning obligations. For instance, the USCs specify maximum permissible noise levels at non-participating residences, minimum setback distances from property lines and public roads, curtailment measures during bat migration periods, and mandatory decommissioning plans backed by financial assurance. By defining these standards up front, ORES provided applicants with clear design targets. Projects can be planned to meet these criteria from the outset, reducing the number of unknowns and the potential for late-stage negotiations. The uniformity also reassures communities that projects are being held to consistent standards, regardless of the developer or the town in which they are proposed.

While the USCs established baseline protections, ORES retains the authority to impose site-specific conditions to address unique circumstances. Examples include requiring visual screening with native vegetation near historic sites or limiting construction hours during sensitive tourism

100 Executive Law section 94-c; former 19 N.Y.C.R.R. Part 900 / 16 N.Y.C.R.R. Part 1100.

seasons. These conditions emerge from consultations with state agencies, local governments, and the public, and they illustrate how ORES can balance uniformity with flexibility, tailoring permits to local contexts without sacrificing the efficiency benefits of the process.



SOURCE | Office of Renewable Energy Siting

FIGURE 4. New York — Office of Renewable Energy Siting Process

A critical structural change is the treatment of local laws in the ORES process. Under the statute, applicants are required to identify applicable local laws and, where necessary, to seek waivers under a new standard, which shifted from Article 10's "unreasonably burdensome in view of technology or cost" to one that considered "the CLCPA mandates and the environmental benefits of the project," explicitly elevating climate policy in the balancing test. In other words, ORES may waive local requirements if it finds they are unreasonably burdensome when balanced against the CLCPA targets and the environmental benefits of the project. This standard explicitly incorporates the state's climate objectives, shifting the analysis from purely technological feasibility to a broader consideration of statewide environmental benefits. In practice, waiver disputes are highly fact- and ordinance-specific. For example, ORES has waived local law provisions such as excessive setback or turbine height limits that would effectively prohibit modern wind turbines.[101] The Office also respected local requirements where they do not undermine project viability.[102] For instance, a town's requirement that solar arrays be set back a certain distance from roadways for public health and safety has been upheld.[103] Because the waiver standard expressly incorporates the CLCPA mandates, future changes to the strength, interpretation, or political durability of those mandates could affect how readily ORES grants local-law waivers, although that question lies beyond the scope of this report.[104]

The early years of its implementation offer evidence that a consolidated, deadline-driven process can accelerate decisions while maintaining robust environmental and community protections. One of the most striking outcomes of the ORES process is the acceleration of decision timelines. Under Article 10, the average time from application filing to final Siting Board decision for renewables was roughly 3.7 years, with some projects languishing for up to eight years.[105] In the first three years of its operation, ORES exceeded the total capacity permitted under Article 10 in the previous nine years combined.[106] By early 2026, ORES had issued 30 final siting permits for large-scale renewable projects.[107] The projects approved spanned onshore wind, solar, and co-located battery energy storage, with sizes ranging from just above 20 MW to 500 MW. They are geographically dispersed across upstate New York, including in the North Country, the Mohawk Valley, western New York, and the Southern Tier. The early permit volume indicated that the regulations and their implementation were not merely theoretical, but a functioning system capable of processing a high throughput of projects.

Despite the shortened timeline, the ORES process has not been a rubber stamp.[108] The process is resource-intensive for applicants and permitting expectations can require expansive technical surveys and studies. Each application generates a detailed administrative record. Developers must submit extensive analyses of potential impacts on wetlands, wildlife, agricultural soils, cultural resources, visual character, noise levels, traffic, and other factors. ORES circulates draft permits with conditions tailored to each project, often spanning dozens of pages. Public comment periods typically yield hundreds of written submissions from local governments, residents, and local groups. ORES holds public statement hearings in host communities to allow oral testimony for every project. In this way, the process creates formal opportunities for community voices and concerns to be heard and considered.

When significant disputes arise, ORES may refer specific issues to an adjudicatory hearing, and when hearings occur, they are targeted rather than full-blown litigation over entire applications. ORES's targeted-hearing model preserves due process while preventing hearings from expanding to the full scope of project impacts. However, its legitimacy depends on clearer signals about what kinds of narrow factual disputes warrant a hearing.

101 Matter of Heritage Wind, LLC, ORES DMM Matter No. 21-00026, Decision of the Executive Director (Jan. 2022).
102 Matter of Bear Ridge Solar, LLC, ORES DMM Matter No. 21-02104, Decision of the Executive Director (July 2023).
103 Matter of Horseshoe Solar Energy LLC, ORES DMM Matter No. 21-02480, Decision of the Executive Director (Dec. 2022).
104 Clean Energy Standard Biennial Review, Case 15-E-0302, Order Adopting Biennial Review as Final (May 2025).
105 Thomas P. DiNapoli, State Comptroller, "Office of Renewable Energy Siting Audit," (April 2024).
106 Office of Renewable Energy Siting, "2024-2025 ORES Budget Testimony" (Feb. 2024).
107 New York Department of Public Service, "DPS Announces Approval of Renewable Energy Project in Montgomery County," (Jan. 2026).
108 Noah C. Shaw, "New York Shows There Is a Path Forward" (Nov 2022).

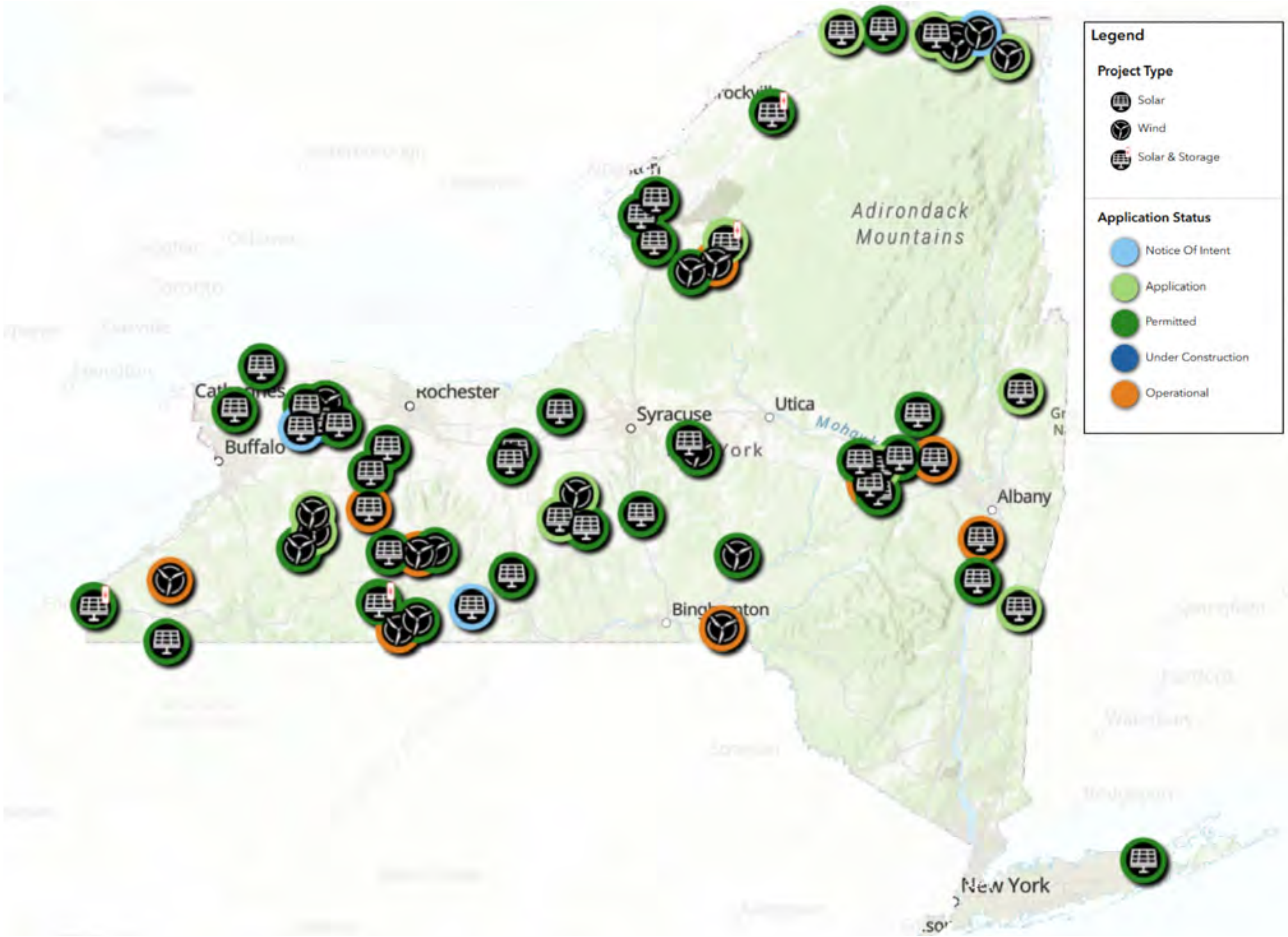


FIGURE 5. New York Renewable Energy Permit Application Status Map[109]

4.3 Identified Gaps and Bottlenecks

Despite these positive outcomes, the early years of ORES reveal several areas where the process' design and implementation could be improved to ensure that renewable deployment continues apace and that host communities feel respected and protected.

Hearing Threshold and Community Voice: The streamlined ORES process relies on a "substantive and significant" standard to determine whether an issue raised by commenters warrants an adjudicatory hearing. This threshold, borrowed from the New York State Department of Environmental Conservation (DEC)'s permit hearing rules, is designed to reserve trial-type hearings for disputes that could plausibly affect the permit outcome, while allowing the Office to resolve narrower or more policy-laden issues through written submissions and permit conditions. In practice, however, municipalities and intervenors do not always have clear guidance on what kinds of factual disputes, evidentiary showings, or expert disagreements will suffice. The process should function akin to "summary judgment," but there is a public

109 New York Department of Public Service, "Renewable Energy Permit Application Status," (accessed Mar. 2026)

perception of heavy deference to agency and developer experts that makes it difficult for municipalities or community groups to craft an acceptable offer of proof. Many of the most contentious aspects of renewable energy siting—such as whether a project harmonizes with community character, whether its visual impacts are acceptable, or how it might affect local quality of life—are inherently qualitative. They do not lend themselves to simple yes or no factual disputes and often fall outside the strict criteria of the law and regulations.

Even where a town submits expert reports contesting the applicant's experts, those submissions have been deemed insufficient to establish a substantive and significant issue requiring a hearing. Municipal representatives therefore question what would, in practice, satisfy the threshold short of proposing an alternative project layout or redesign—an exercise many towns cannot realistically afford. Under compressed timelines and without broader discovery tools, stakeholders can struggle to develop the kind of evidentiary record needed to prove an issue is "substantive" enough to justify a hearing. There is a perception that the new process, by curtailing prolonged hearings, also diminished the opportunity for face-to-face dialogue and trust-building that sometimes occurred when parties met in extended proceedings.

To date, only a few adjudicatory hearings have been granted, which has fueled frustration among host municipalities that have submitted expert testimonies and still failed to secure an evidentiary hearing. That frustration is especially acute in local-law waiver disputes, where towns may regard major reductions in setbacks or other requirements as outcome-determinative yet still struggle to satisfy the Office's hearing standard. For instance, the Office's explanation for granting a waiver at the draft-permit stage is not always detailed or transparent. Staff's recommendations to grant waivers sometimes state only that the determination is made "based upon the record in this case," without clearly identifying which arguments or evidence ORES has adopted. Although applicants typically provide varying levels of support in their local-law compliance filings, municipalities may still be left to infer ORES's actual reasoning until later briefing or a final decision clarifies it. This opacity can be especially unsatisfying where applicants present multiple overlapping justifications and towns must respond on appeal without knowing precisely which rationale carried the day.

Put simply, while everyone retains the right to submit comments and objections under the statute and its implementing regulations, the more compressed, paper-focused nature of the process can leave some intervenors feeling that, while they had an opportunity to file material, a primarily written, compressed process limited their opportunity to probe evidence through hearings. The resulting frustration is less an argument against the targeted-hearing model itself than a signal that the Office should provide clearer explanations of when a hearing is warranted and why particular disputes are being resolved on the papers rather than through testimony. There is a delicate balance since the very purpose of the reform was meant to avoid quasi-litigation for every project, yet the state must remain attentive to whether procedural efficiency is being achieved at the expense of perceived fairness and community voice. The challenge is therefore to ensure meaningful participation and to provide other avenues for dialogue on complex, value-driven issues.

Engaging Local Governments: The statute requires applicants to consult with host municipalities about local requirements and to notify them at least 60 days prior to filing an application. In theory, this ensures early engagement with those most familiar with a community. While some local officials have praised developers for collaborating early and often, incorporating town feedback into project plans, others have reported feeling left out or overwhelmed under the new process. Some developers treated the rules as satisfied by holding a single meeting with a town and then proceeding through the process, leaving substantive local concerns unaddressed and poisoning the well for the rest of the process. Smaller towns especially may lack professional planners or attorneys versed in renewable energy, and they find it challenging to keep up with the regulatory details or to respond within the tight consultation and comment windows.

While the RAPID Act regulations provide more detailed guidance by turning early engagement into explicit procedural gates, the quality of consultation still relies heavily on the developer's discretion. As a result, actual practices could still vary widely—from iterative, problem-solving engagement to perfunctory, one-meeting consultations that satisfy the letter of the rule but not its spirit. In cases where a developer and a town disagree from the outset on fundamental questions, there is still no structured mediation or facilitation mechanism in the current process to bridge that gap. Local governments possess invaluable knowledge about their areas' land use priorities, environmental sensitivities, and residents' sentiments. Harnessing this knowledge early could lead to projects that are better tailored to local context and thus smoother to approve. The primary gap is that neither the statute nor the regulations fully tap into the potential of local governments as partners. The law gives them a voice but not necessarily a defined role in shaping outcomes beyond raising objections. There are continued calls for more robust state guidance on community engagement best practices to ensure these meetings are more than just a procedural checkbox.

Completeness and Front-Loaded Challenge: In the ORES process, completeness triggers the statutory decision clock and signals that the application record is sufficient to support the issuance of a draft permit. By and large, ORES has adhered to the 60-day rule, but stakeholders have observed that the stringency of determinations can vary. Some applications sail through with minimal requests, while others receive extensive notice of incompleteness. Because incompleteness determinations are not formally appealable, some applicants describe the completeness gate as high-discretion and inconsistent across projects, which they believe has injured the office's credibility and leaves them with little practical recourse beyond informal escalation. The RAPID Act regulations push the process further toward an explicitly iterative model, making it easier to start the clock once ORES can begin drafting conditions while leaving more data supplementation to later phases. There is a risk, however, that if ORES errs on the side of deeming applications complete too readily, important issues might only surface later, compressing the time available to address them. Achieving consistency in this review remains crucial.

Both developers and community stakeholders would benefit from greater transparency on what a complete application must contain versus what can follow as a compliance filing. The regulations enumerate required exhibits, but the level of detail remains subjective. One practical bottleneck is seasonal field work—for instance, wildlife surveys might not be completed by the filing date. While the RAPID Act framework could help manage these realities by allowing for late supplementation, it would require clear delineation of how that data will be disclosed and tested on the record. Thus, while the 60-day rule is a boon for predictability, its execution must be managed transparently to ensure it does not become a source of perceived arbitrariness or a checkbox that ignores substantive issues.[110]

Interagency Coordination: Although ORES was designed as a one-stop shop, it does not operate in a vacuum. The Office relies on input from various state agencies with domain expertise: DEC for wildlife and wetlands; the Department of Agriculture and Markets for farmland impacts; the Office of Parks, Recreation and Historic Preservation for cultural resources. The statute consolidates final decision authority in ORES, and it explicitly contemplates that ORES will consult these agencies and may even defer to certain determinations. However, early indicators suggest that these interagency consultations under the RAPID Act are becoming a new source of delay, mirroring some of the complexities seen in the former Article 10 proceedings.[111] The efficiency of the ORES timeline assumes that inputs from sister agencies will arrive and be resolved within strict statutory and regulatory windows. If those inputs are late or if conflicts between agencies and developers remain unresolved, ORES will face a choice between delaying its completeness determination or issuing a permit with extensive conditions that punt unresolved issues to the post-permit compliance phase.[112]

Either outcome can undermine the credibility of the one-stop promise.[113] Moreover, from the public's perspective, these interagency dealings are not always transparent. A community group might not know that a wildlife habitat issue is being hashed out behind the scenes, which could create the appearance that a project was approved without addressing key concerns and impacts. The structural challenge is to better integrate interagency review so that it is both expeditious and visible on the public record. While formalizing timelines for agency feedback helps, interagency consultation remains a potential pressure point that could slow the pace of approvals or create gaps in the perceived thoroughness of reviews.

Post-Permit Compliance: A critical yet sometimes overlooked phase of the siting process is what happens after a permit is issued but before and during construction. The permits issued by ORES, much like certificates under Article 10, come with extensive conditions that a developer must satisfy, often through additional plans, reports, or approvals that must be submitted to ORES or other agencies. These can include final engineering plans, traffic management plans, invasive species control plans, detailed wetlands mitigation plans, notices of any changes in equipment or layout, and so forth. While these conditions are necessary to ensure that the project as built lives up to the promises made during permitting, they can create a secondary bottleneck if not managed efficiently.

There can be long gaps between permit issuance and the start of construction, leaving projects hanging over host communities for years. When construction finally begins, towns may face another wave of opposition from residents. This post-permit phase can be especially frustrating for local communities because much of it occurs out of public view. ORES has at times informally considered town comments on compliance filings and appears to have encouraged

110 Hodgson Russ LLP, "RAPID Action: ORES Issues Revised Proposed Regulations Under the RAPID Act" (Nov. 6, 2025).

111 Noah Shaw & Devlyn Tedesco, "Through the RAPID Act, the NYPSC is Losing Jurisdiction Over Transmission Siting – Or Is it?" (May 2024).

112 Noah Shaw, Sarah Main, & Elza Bouhassira, "Wading Into NY Wetland Regs' 2025 Changes and Challenges" (Nov. 2025).

113 Michael N. Boncardo, John W. Dax, & Jenna M. Rackerby, "RAPID Act Revisions: ORES' Proposed Changes Will Reshape Project Timelines for the Worse" (Dec.2025).

engagement, but that practice depends heavily on case-specific relationships and may be tested where pre-application consultation went poorly or local opposition remains strong. Some host agreements fund a town liaison, but that support depends on developer negotiation rather than a standardized state entitlement. Local agency account funding is often exhausted during the permitting phase, even though post-permit road-use, construction, and compliance issues can require continued municipal attention.

More broadly, as the ORES pipeline matures from permitting into simultaneous construction and compliance phases, the state will need to monitor whether DPS has sufficient staffing to oversee projects consistently. That risk becomes more salient if clusters of permitted projects in western New York and elsewhere begin construction on overlapping schedules in 2026 and 2027. If a developer receives a permit but then spends a year resolving issues such as a wildlife mitigation plan or road-use agreement, that delay can erode the time gains achieved during permitting and reinforce public skepticism that post-permit obligations are not being monitored transparently. The gap here is therefore not only transparency, but also role clarity, staffing, sequencing, and sustained resourcing for post-permit oversight.

Local Equity and Social License: Renewable energy facilities, by their nature, concentrate certain impacts locally while dispersing environmental benefits statewide. This raises issues of distributive justice as some communities may feel they are asked to shoulder burdens for the good of the state, and historically, those feelings can spur backlash. The reformed siting process attempted to address this through a couple of mechanisms. One is the required Host Community Benefit Program, which provides electricity bill discounts to residents in host communities. In practice, however, these discounts are often modest—commonly on the order of roughly \$50 to \$75 per year—and their town-wide distribution can mean that households largely unaffected by a project receive the same benefit as those nearest to it. Developers may also treat the required Host Community Benefit Program as part of the overall community-benefit package when negotiating host agreements; under the current program, solar facilities pay \$500 per MW annually and wind facilities pay \$1,000 per MW annually for the first ten years of operation, which can dilute the incremental value of the state benefit from the host municipality's perspective.[114]

Another mechanism is intervenor funding and public participation requirements designed to give communities voice and resources. However, these measures do not fully guarantee a sense of local ownership or acceptance. Some local officials also worry that expanding a state-managed host-benefit framework could inadvertently crowd out or standardize downward the locally negotiated host agreements that often reflect project-specific impacts and bargaining dynamics. The gap remains that some communities simply do not want large renewable projects regardless of process, and the state has not articulated a clear policy on what happens if an entire community is steadfastly opposed to a project. ORES can issue a permit over local objections—and it has done so—but that does not magically resolve underlying discontent. The current framework focuses on permitting, but long-term success may require a more holistic community engagement strategy that extends through construction and operation.

114 Ruby Moore-Bloom, Clean Energy Transition Institute, "Ensuring Communities Benefit from the Clean Energy Transition," (Sep. 2024); New York Department of Public Service, "Staff Report on the Implementation and Effectiveness of the Host Community Benefit Program," (June 2023).

Prepared local governments and well-informed communities are key to the state's energy transition. The state should dedicate more resources to help localities plan for and cope with being host communities—effectively treating renewable infrastructure as a facet of community development rather than as an external imposition. Failing to do so risks a buildup of local resentment that could translate into political pushback or demands to roll back parts of the siting reform. Local acceptance is therefore not merely a normative concern about fairness; it is becoming a practical condition of sustained deployment in a state where formal preemption exists, but durable implementation still depends on municipal cooperation and community tolerance.

Deliverability, Affordability, and Political Durability: Even a perfect siting process cannot, on its own, ensure CLCPA goals are met. ORES addressed one critical piece of the puzzle—getting projects approved—but other systemic bottlenecks have started to move to the forefront. The most notable of these is the grid's capacity to absorb and realize new generation. New York's bulk transmission system and local distribution grids in many areas are nearing saturation with respect to how many additional renewable energy projects they can handle without major network upgrades. Large solar and wind projects enter the NYISO interconnection process, where multi-year study, cost-allocation, and agreement timelines can delay projects even after they receive siting approval. Those queue-related delays are distinct from, but often compounded by, later constraints such as transmission construction, substation work, procurement timing, and contract viability.[115]

A further second-generation constraint is political and economic durability. Economic factors like successful state procurement solicitations, supply chain constraints, and workforce availability all play a role in deliverability. Public debate over CLCPA implementation had shifted beyond permitting speed to include the affordability of compliance, the effects of federal funding instability and federal permitting headwinds, supply-chain and inflationary pressures. In that environment, the legitimacy of the siting regime depends not only on whether ORES can issue permits quickly, but also on whether the broader deployment pathway remains affordable and politically maintainable. A fast-permitting system cannot by itself secure climate progress if the underlying transition loses fiscal or political support.

The gap, in essence, is that a fast permit is necessary but not sufficient. ORES addressed a major bottleneck in project approval, but approval does not guarantee construction or operation. Many projects now confront downstream barriers in interconnection, transmission availability, procurement design, contract viability, and post-permit approvals. New York's experience therefore suggests that permitting reform can materially improve approval timelines without, by itself, ensuring timely deployment. The holistic picture requires aligning the siting process with these other elements—something that is beyond ORES's direct control. It falls to the broader energy policy apparatus of the state to ensure that as ORES feeds projects into the pipeline, there are parallel efforts to clear the downstream obstacles. Otherwise, there is a risk of paper success where many projects have permits in hand but fewer reach commercial operation on the needed schedule. Such an outcome would undermine the purpose of the siting

115 LBNL, "Queued Up: 2025 Edition" (Dec. 2025).

reform and could create public cynicism.[116]

In summary, the gap analysis reveals that while New York's reformed siting process has addressed the major failings of the previous system, it now faces second-generation issues. These range from procedural fine-tuning of how to better incorporate local input and manage completeness and hearings to broader systemic coordination. The next section turns to recommendations for how the state can respond to these gaps, fortifying the siting regime for the crucial years to come when renewable deployment must dramatically accelerate.

4.4 Recommendations

New York's early experience with ORES demonstrates that a unified, time-bound process can dramatically increase the pace of renewable permitting while maintaining environmental integrity. However, to fully realize the state's climate goals and sustain public acceptance, targeted improvements are needed. The following recommendations address identified gaps and aim to strengthen predictability, transparency, and community trust without sacrificing efficiency, and are explored in further detail below:

Provide Detailed Guidance and Standardized Checklists: To reduce uncertainty at the front end of the process, ORES should develop comprehensive guidance documents detailing what constitutes a complete application for various project types. These guidance materials should include checklists enumerating required field surveys and modelling outputs, mitigation plans, and consultation documentation. They should further clarify how to handle seasonal constraints and specify the level of detail needed at the time of filing versus what can be provided later. Publicly available templates would enable developers to prepare high-quality submissions and would allow municipalities and communities to know what to expect.

Create a Permitting Affordability and Cost Containment Task Force: Because the cost of project development can rise materially during the siting process as additional studies, mitigation measures, and permit conditions are layered onto an application, New York should convene a task force to identify opportunities that reduce unnecessary developer cost without weakening environmental review or public participation. The task force should review which application requirements are genuinely outcome-determinative, which can be standardized or consolidated, which can be deferred to post-permit compliance without prejudice to informed decision-making, and where interagency review is generating avoidable duplication or late-stage redesign. That review could include whether some interconnection materials should be streamlined, whether overlapping reports can be consolidated, and whether certain supporting information can be standardized by template rather than recreated in each case. The goal should not be to weaken environmental review or community protection, but to reduce avoidable cost escalation and improve predictability for applicants, agencies, and host communities. Framed properly, this recommendation would better align the ORES process with the State's broader affordability direction by focusing not only on speed, but also on cost discipline and predictability.

116 Office of the New York State Comptroller, Division of State Government Accountability, "Climate Act Goals – Planning, Procurements, and Progress Tracking," (July 2024).

Formalize Early Community Engagement Frameworks: Meaningful community engagement cannot be limited to comment periods, and it must begin before a permit application is filed. The regulations set minimum expectations for timing, format, responsiveness, and documentation of follow-up. ORES should require developers to prepare more effective community engagement plans. These plans should outline how developers will inform residents of proposed projects, gather feedback, and document how that feedback influenced project design. Early engagement should include community meetings, stakeholder workshops, and open houses with accessible information.

Increase Transparency and Rationale in Local Law Waivers: Waiving local laws is an inherently sensitive action because it can appear to override local autonomy. ORES should provide clearer, project-specific explanations of waiver decisions at the draft-permit stage rather than relying on generic formulations. Those explanations should identify the principal arguments and evidence the Office has accepted, distinguish them from alternative arguments it has not relied upon, and describe why compliance with the local law was or was not feasible.

ORES could compile an annual report summarizing all waivers granted and denied, including the reasoning behind each decision. Such a compilation would show patterns in how certain recurring local issues—such as setbacks—are treated and provide guidance to municipalities on crafting ordinances that are likely to be respected. When local governments and developers clash over a particular requirement, ORES might facilitate mediation and preserve a credible pathway for meaningful dispute resolution within the administrative process, including well-structured evidentiary hearings where appropriate. Structured hearings that confine disputes to outcome-determinative issues can be faster and enhance legitimacy more than unstructured conflict that later migrates to court. A transparent, principled approach to waivers can reassure towns that they are not being arbitrarily overruled and can help developers understand the limits of local deference.

Streamline Post-Permit Compliance: To prevent the post-permit phase from becoming a hidden source of delay, ORES should improve communication with host communities during post-permit compliance and clarify how municipalities may submit input on major compliance filings, without creating any additional municipal approval requirement. Local agency account funding, or a comparable mechanism, should also remain available for key post-permit issues such as road-use agreements, construction monitoring, and review of major compliance filings. Any additional transparency measures in the post-permit phase should be designed to inform affected municipalities and residents, not to create a new veto point or reopen settled permit determinations once a project is moving into construction.

In cases where modifications to a project arise as developers refine equipment models or layouts, ORES should apply a clear threshold test to decide if a modification is “major,” necessitating public notice or revision of the permit, or “minor,” which can be handled as a field change. Defining those categories with examples would avoid any perception that projects are being altered post-approval without oversight.

Coordinate Siting with Grid Planning and Procurement: To ensure that permitted projects are built and deliver power, the siting process should be integrated with transmission planning and procurement. New York should align ORES approvals with NYISO's interconnection queue and the state's transmission planning. The state could also expedite approval for transmission projects that unlock multiple renewable facilities, recognizing that transmission lines often require longer lead times. Regular public reports linking permitted generation to grid upgrades, procurement contracts, and expected commercial operation dates would keep stakeholders informed and help ensure that siting success translates into delivered megawatts. Moreover, the state might consider better coordinating state large-scale renewable solicitations with project readiness to avoid awarding contracts to projects that cannot interconnect within required timelines.

Support Local Equity and Social License: Achieving social license requires more than tangible, long-term benefits for host communities. Any future adjustment to host-community benefits should be approached cautiously so that statewide programs supplement rather than displace locally negotiated host agreements or become a de facto benchmark for reducing local contributions. The more immediate priority is preserving room for project-specific host agreements while improving front-end technical assistance, transparency, and follow-through for host communities.

Recognizing that small towns often lack technical expertise, New York should prioritize front-end technical assistance for municipalities and intervenors so that the consolidated process does not widen the capacity gap between well-resourced developers and smaller local governments. That assistance could include funding for independent technical review, standardized templates for local submissions, and practical guidance on what issues can be raised, when, and through what procedural vehicles. A practical framework could pair communities with third-party facilitators who specialize in renewable energy siting, helping translate technical documents into plain language and identifying potential concerns early. These measures would turn early notice into early problem-solving rather than a perfunctory step.

Implementing these recommendations would require a mix of administrative action by DPS and other agencies. However, they are largely in line with the spirit of the existing law. The underlying philosophy remains that time is of the essence in the climate fight, and a well-designed process can achieve speed without forsaking fairness or environmental integrity. By addressing the identified gaps, New York can fortify its siting process as a model that other states might emulate—a model that reconciles the need for rapid infrastructure development with the demands of public accountability and local empowerment.

4.5 Conclusion

The creation of ORES has reshaped New York's renewable energy landscape by replacing a protracted permitting system with a unified, time-bound process. Early results show that ORES has issued more permits in a few years relative to the state's historical pace, adding a substantial volume of permitted capacity, while still producing detailed records, imposing rigorous environmental and community protections, and withstanding judicial scrutiny. However, permit volume alone is not enough to establish success. The stronger analytic lesson is that

ORES' value lies in its process design: a single siting office with structured pre-application procedures, tailored application requirements, uniform standards, defined completeness deadlines, a binding decision clock, and a single accountable decisionmaker.

Yet centralization also carries risks, including perceptions of state overreach, participation dilemmas, uneven local engagement, variability in completeness determinations, interagency coordination challenges, capacity bottlenecks inside the agency, and the possibility that conflict migrates into front-end design work or post-permit compliance. These gaps do not undermine the fundamental logic of the reform, but they highlight the need for continuous improvement.

Ultimately, the success of New York's renewable energy siting reform will be evaluated not only by the speed with which permits are issued but by the extent to which permitted projects are constructed, interconnected, and deliver clean power on schedule; by the degree to which host communities feel heard and fairly compensated; and by the durability of legal frameworks that balance climate urgency with democratic accountability. The next phase of reform may therefore be evaluated not only by the scale, speed, and quality of review, but by whether New York can pair ORES's permitting capacity with credible transmission planning, interconnection reform, procurement discipline, and an investment environment that keeps projects financeable, buildable, and politically sustainable.

5 WASHINGTON

Washington State's clean energy siting debate illustrates the broader challenge facing jurisdictions that have adopted ambitious decarbonization targets while upholding rigorous environmental protections, Tribal sovereignty, and local control. Under the Clean Energy Transformation Act (CETA), retail electricity must be greenhouse-gas neutral by 2030 and supplied by 100% clean electricity by 2045.[117] The Climate Commitment Act (CCA) established a complementary economy-wide cap-and-invest program,[118] and voters rejected Initiative 2117 in November 2024, preserving the CCA and signaling continued political support.[119] Under the Healthy Environment for All (HEAL) Act, the state further requires that benefits of the clean energy transition be shared with overburdened communities and that no group bears disproportionate burdens.[120]

Electrification of transportation, buildings, and portions of industry is widely expected to increase Washington's electricity consumption substantially. State Energy Strategy modeling estimated that demand could rise by roughly 97% above 2020 levels by 2050 under an electrification case, with even higher demand under scenarios that include large new

117 Clean Energy Transformation Act, ch. 19.405 RCW, (WA 2019)
118 Climate Commitment Act, ch. 70A.65 RCW, (WA 2021).
119 Washington Secretary of State, "Initiative Measure No. 2117 - County Results," (Nov. 2024).
120 Washington Healthy Environment for All (HEAL) Act, E2SSB 5141, (WA 2021).

industrial loads.[121] Meeting that scale of growth would require sustained build-out of wind, solar, storage, and other resources, amplifying the state's longstanding geographic mismatch: strong renewable resources and lower-cost land are concentrated east of the Cascades, while major load centers sit in the Puget Sound corridor. Bridging that divide with new transmission is a fundamental delivery challenge, and stakeholders have already identified interconnection backlogs as a growing constraint. [122]

Washington's energy siting debate does not occur in isolation. The West Coast functions as a regional energy ecosystem where California and Oregon maintain similarly aggressive mandates. Regional coordination on resource adequacy, transmission planning, and market integration—including through the Western Resource Adequacy Program and potential organized wholesale markets—is increasingly vital. Because projects may serve multistate markets and navigate multiple permitting regimes, a clear and predictable siting framework within Washington is essential for both in-state initiatives and interstate projects.

Against this backdrop, Washington's siting and permitting architecture must balance administrative speed with procedural rigor, statewide benefits with local impacts, and climate imperatives with environmental justice and Tribal rights. The sections that follow describe how Washington's pre-reform system functioned, why it struggled to produce timely and durable decisions, and how the state's recent reforms attempt to reallocate conflict earlier and more predictably rather than simply compressing the final stages of review.

5.1 Pre-Reform Landscape

Washington's contemporary disputes over clean energy siting emerged from an older institutional bargain designed to prevent major infrastructure decisions from dissolving into a fragmented contest among competing agencies, jurisdictions, and constituencies. The state entered the current reform era not with a deficit of process, but with a dense constellation of laws and jurisdictions capable of producing voluminous administrative records and exhaustive environmental studies.

The State Environmental Policy Act (SEPA), enacted in 1971, mandates that government agencies evaluate the environmental consequences of major actions, requiring detailed Environmental Impact Statements (EIS) for projects with significant adverse effects. The Growth Management Act (GMA), enacted in 1990, empowers local governments to adopt comprehensive plans and zoning regulations, including critical areas ordinances designed to protect wetlands, wildlife habitats, and sensitive resources.[123] Federally recognized Tribes maintain treaty-reserved rights that must be upheld in any state action, while the National Historic Preservation Act (NHPA) and other federal statutes require rigorous consultation regarding cultural resources.[124] Involvement from federal entities—such as the Bonneville Power Administration (BPA) or the Federal Energy Regulatory Commission (FERC)—further triggers NEPA, adding another layer of review.

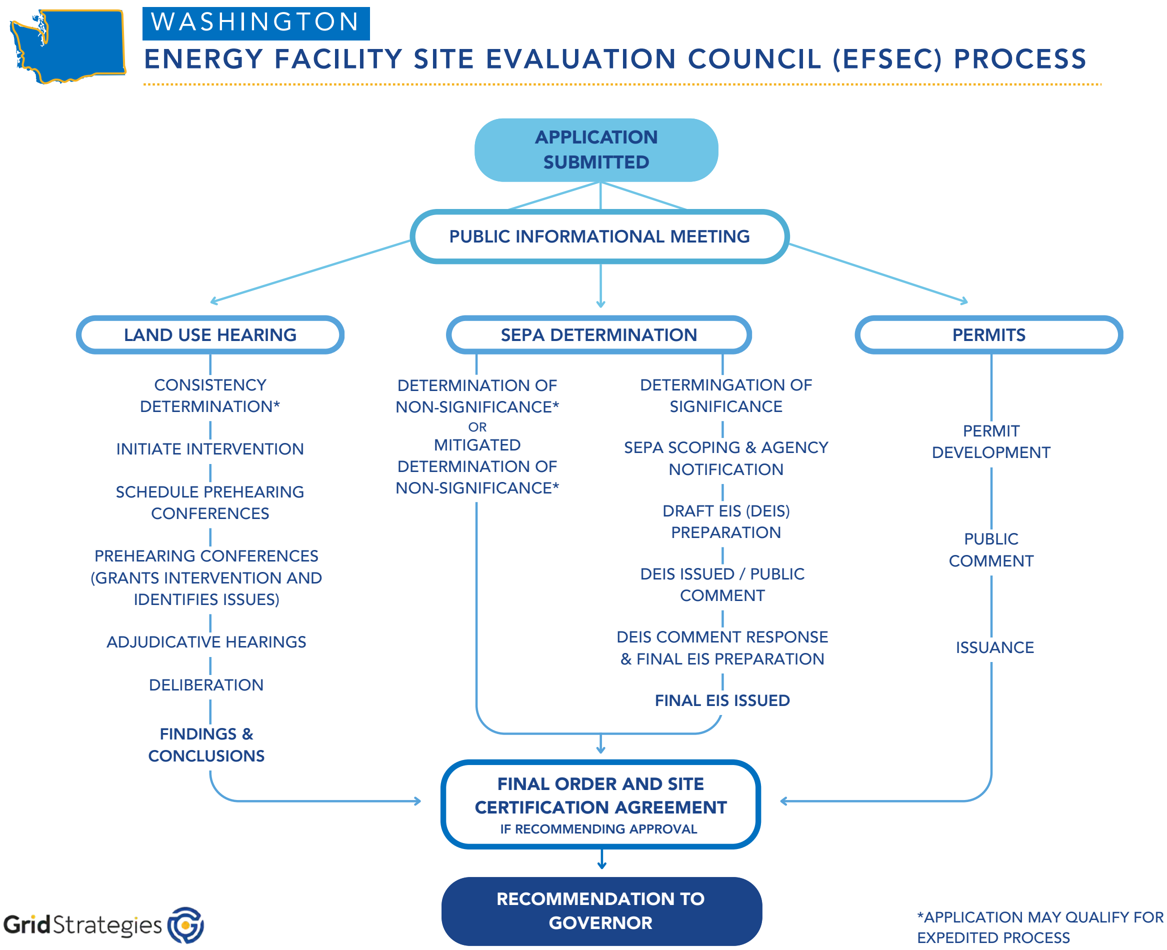
121 Washington State Department of Commerce, "Washington 2021 State Energy Strategy," (Dec. 2020) at 35.
122 Interagency Clean Energy Siting Coordinating Council, "Clean Energy Project Siting: Report to the Legislature," (Oct. 2025).
123 Growth Management Act, ch. 36.70A RCW, (WA 1990).
124 Washington State Office of Equity, "Honoring our Treaties," (accessed Mar. 2026).

This multi-layered environment ensures that any energy project encounters a series of decision gates, each governed by distinct timelines, evidentiary standards, and avenues for appeal. The functional independence of many agencies compounds the complexity. Developers often describe a regulatory choreography in which they must precisely sequence permit applications and consultations to avoid duplicative studies or closed windows of opportunity. Without central alignment, issues that should be resolved early—such as study methodologies or mitigation frameworks—are frequently revisited, undermining predictability.[125]

To help address this fragmentation, the Energy Facility Site Evaluation Council (EFSEC or the Council) was established in 1970 to provide a consolidated one-stop process for major energy facilities.[126] Operating as a multi-agency body, EFSEC comprises representatives from key state departments—including Ecology, Fish and Wildlife, and Natural Resources—ensuring that diverse regulatory mandates are reconciled within a single forum. From its inception, the governing statute has framed EFSEC's role as an explicit balancing exercise of facilitating energy facilities that meet state needs while minimizing environmental impacts. EFSEC's consolidated structure is intended to pull public participation and agency tradeoffs into one decision-forcing forum rather than leaving them to uncoordinated and sequential review.[127] EFSEC is empowered to define application requirements, conduct formal hearings under the Administrative Procedure Act, and issue recommendations for site certification.[128] Crucially, the Council serves as the lead agency for SEPA, allowing it to integrate environmental reviews and exercise substantive authority to mitigate impacts through a single Site Certification Agreement.

A distinctive feature of this process is the Counsel for the Environment—an attorney appointed by the Attorney General to represent the public interest in environmental quality—who participates as a formal party in EFSEC proceedings. The Council's structure is inherently quasi-judicial; applications often trigger adjudicative proceedings involving formal intervention, sworn testimony, and cross-examination. While EFSEC has the authority to preempt local land-use ordinances upon the Governor's approval, this power does not extend to Tribal sovereignty: EFSEC must navigate treaty rights and government-to-government consultation obligations. A certificate also does not grant automatic site control; developers must still negotiate proprietary land rights and easements, particularly on state-trust lands managed by member agencies.

125 Ecology, "Considerations for Consolidating Clean Energy Permits and Applications," (Oct. 2024).
126 Washington State Energy Facility Site Evaluation Council ("EFSEC"), "History and Mission," (accessed Mar. 2026).
127 Margaret H. Hornbaker & William H. Rodgers, Jr., "The Evolution of the Energy Facility Site Evaluation Council" (2001).
128 Energy Facilities Site Locations Act, ch. 80.50 RCW (WA 1970)



SOURCE | EFSEC Process Overview (May 2024)

FIGURE 6. Washington—Energy Facility Site Evaluation Council Process

Despite this robust authority, EFSEC was rarely the default pathway for renewable energy projects before recent reforms.[129] Local permitting often appeared more flexible and expeditious, particularly in supportive counties. EFSEC proceedings were frequently viewed as lengthy and resource-intensive; the mandate to build a defensible record across multiple jurisdictions fostered a quasi-judicial culture that deterred many applicants.[130] Historically, EFSEC's mandatory jurisdiction was tied to large thermal and nuclear plants, leaving significant questions about how the Council would manage large-scale clean energy projects.

For most utility-scale renewable projects, the local lane operated less as a singular approval and more as a sequenced set of interlocking land-use and environmental decisions whose combined tempo was often dictated by the slowest permit, the most contested standard, or the most appealable step.[131] Under GMA, counties and cities exercise zoning authority, apply

129 Sophie Doudon, Spencer Checkoway, Caroline Resor, "State of Washington Renewable Energy Policy Analysis Report," (Dec. 2023) at 20.

130 Beveridge & Diamond, PC, "Siting and Permitting Reform in Washington: A Report to the Washington Department of Commerce Under RCW 43.394.020(3)(a)" (June 2024).

131 Washington State Department of Ecology ("Ecology") & Washington State Department of Commerce ("Commerce"), "Low-Carbon Energy Project Siting Improvement Report: Report and Recommendations for Improving Siting and Permitting of Industrial Clean Energy Facilities" (Nov. 2022).

comprehensive plan policies, and implement critical areas protections. Local jurisdictions issued the core discretionary entitlements—typically Conditional Use Permits—while simultaneously serving as the SEPA lead agency. State and federal authorizations proceeded in parallel, creating a gauntlet where uncertainty accumulated whenever any one component—particularly Tribal consultation—became contested or technically underdefined.

Local processes varied significantly in technical capacity and interpretive orientation, causing permitting outcomes to diverge sharply across county lines even for identical projects. Because many utility-scale projects were not permitted by right, determinations of "compatibility" and "public interest" were adjudicated in high-stakes public hearings where technical evaluation and political accountability coexisted uneasily. A proposal could be treated as routine infrastructure in one jurisdiction and as a referendum on local identity in another. This volatility was heightened by local governments' retention of powerful tools to reshape rules mid-process. Because Washington's vested rights doctrine can lock in a developer's rights at the time of filing, some counties adopted emergency moratoria to freeze new applications while rewriting siting ordinances, creating a moving target where a project feasible during land acquisition could become nonconforming by the time an application was processed.[132]

SEPA further magnified this unpredictability because its legal posture extends beyond mere disclosure into the substantive authority to condition or deny proposals. The threshold question of whether a project required a full EIS often became the primary site of conflict. Because the statutory clock for a decision frequently does not start until an application is deemed complete, local agencies could effectively extend timelines through iterative information requests. For controversial projects, an EIS could take years, inviting cycles of study requests and challenges to analysis sufficiency. Even a Mitigated Determination of Nonsignificance could be used strategically through conditions that, while nominally an approval, rendered the project financially non-viable. In practice, the threshold determination often became the de facto negotiation point where information demands, mitigation expectations, and litigation risk were settled, shaping whether a project's design was stable enough to finance.

The appeal architecture of the local lane made strategic litigation rational. Local determinations were frequently appealed to Superior Court via the Land Use Petition Act, creating layered litigation exposure that added years of uncertainty.[133] Delay functioned as leverage rather than a neutral byproduct of review: developers learned to avoid jurisdictions with a history of successful challenges, while opponents learned that multi-step appeals could alter bargaining dynamics long before a project reached construction.

Tribal sovereignty and the protection of cultural resources represented an additional determinative layer that, while structurally central to Washington's legal landscape, remained unevenly integrated into local permitting practice. Washington is home to twenty-nine federally recognized Tribes, many with treaty-reserved rights—including fishing, hunting, and gathering in usual and accustomed places—that extend well beyond reservation boundaries. Because high-quality wind and solar resources often overlap with ancestral landscapes and treaty-reserved

132 Municipal Research and Services Center, "Vested Rights" (accessed Mar. 2026), https://mrsc.org/explore-topics/planning/administration/vested-rights
133 Land Use Petition Act, ch. 36.70C RCW (WA 1995).

use areas, Tribes are frequently both potential hosts and sovereign rights-holders affected by off-reservation development.

While the Centennial Accord of 1989 and subsequent state directives formalized government-to-government consultation expectations for state agencies, cities and counties are not bound in the same way, even though local jurisdictions often served as SEPA lead agencies and therefore controlled the early framing of review. Many local governments lacked the relationships, technical expertise, and budgets needed to conduct meaningful engagement or to recognize that cultural resources can encompass culturally significant landscapes, viewsheds, and traditional use areas rather than only discrete archaeological sites.[134]

This mismatch repeatedly produced late-stage conflict. Some Tribes prefer to engage directly with state officials to honor sovereignty and protect the confidentiality of sacred sites and traditional cultural properties. When local governments led review without early, well-resourced consultation pathways, cultural concerns surfaced only after a project's footprint, mitigation strategy, and financial assumptions had hardened. Late discovery could transform what might have been an early siting adjustment into a high-stakes dispute, making the system more prone to denial, major redesign, or litigation—and eroding the predictability and durability of permitting outcomes.

The pre-reform landscape was also shaped by overlapping federal requirements that introduced schedule risk beyond Washington's direct control. Federal approvals operated as independent critical-path constraints: they could trigger NEPA, impose separate consultation duties, and proceed on timelines misaligned with state decision calendars. In theory, NEPA and SEPA analyses could be jointly prepared; in practice, coordination was uneven, and projects sometimes produced separate EIS documents or parallel technical studies to satisfy different agency mandates. The result was a recurring pattern in which a state or local record could be mature enough to support a decision while federal approvals lagged—or state permits could issue before federal reviews were complete, preserving formal progress while the project remained unbuildable.

These federal overlaps amplified schedule risk and reinforced the strategic importance of pathway choice. Because the state did not consistently allocate projects to a single pathway based on clear criteria, developers selected the lane offering the best mix of speed, flexibility, and predictability rather than treating pathway selection as a straightforward jurisdictional question. In supportive counties, local permitting could feel faster and more negotiable; EFSEC, by contrast, was often perceived as the lane of last resort—even though it offered consolidation and, in theory, greater finality.[135]

Opponents behaved strategically as well, selecting the forums and procedural moments offering the greatest leverage—challenging SEPA threshold determinations, contesting local discretionary approvals, or pressing issues into whichever venue created the most delay. This strategic dynamic consumed time and resources that might otherwise have been spent resolving substantive siting issues early and could produce inequitable outcomes, as

134 Ecology & Commerce, "Low-Carbon Energy Project Siting Improvement Report," at 55.
135 Beveridge & Diamond, PC, "Siting and Permitting Reform in Washington," at 23.

communities with greater organizational capacity were better positioned to extend timelines regardless of whether the underlying issues were meaningfully different.

Pre-reform permitting performance was defined less by the presence or absence of legal authority than by the volatility of gateway decisions governing when the clock truly began and whether approvals translated into a buildable project. EFSEC's statute set a one-year target for recommendations, but that timeline did not start until an application was deemed complete, and completeness determinations could become contested precisely because they controlled whether the system moved from open-ended information exchange into a decision-forcing calendar. Local processes lacked firm statutory deadlines, and moratoria or ordinance amendments could suspend proceedings entirely. The result was a system capable of generating extensive process and documentation without consistently producing timely, durable decisions. As statutory commitments tightened the delivery window, that mismatch became harder to manage—not because environmental protections, Tribal consultation, and public participation were dispensable, but because the system often failed to translate those legitimate requirements into early clarity and a stable, closure-grade record.

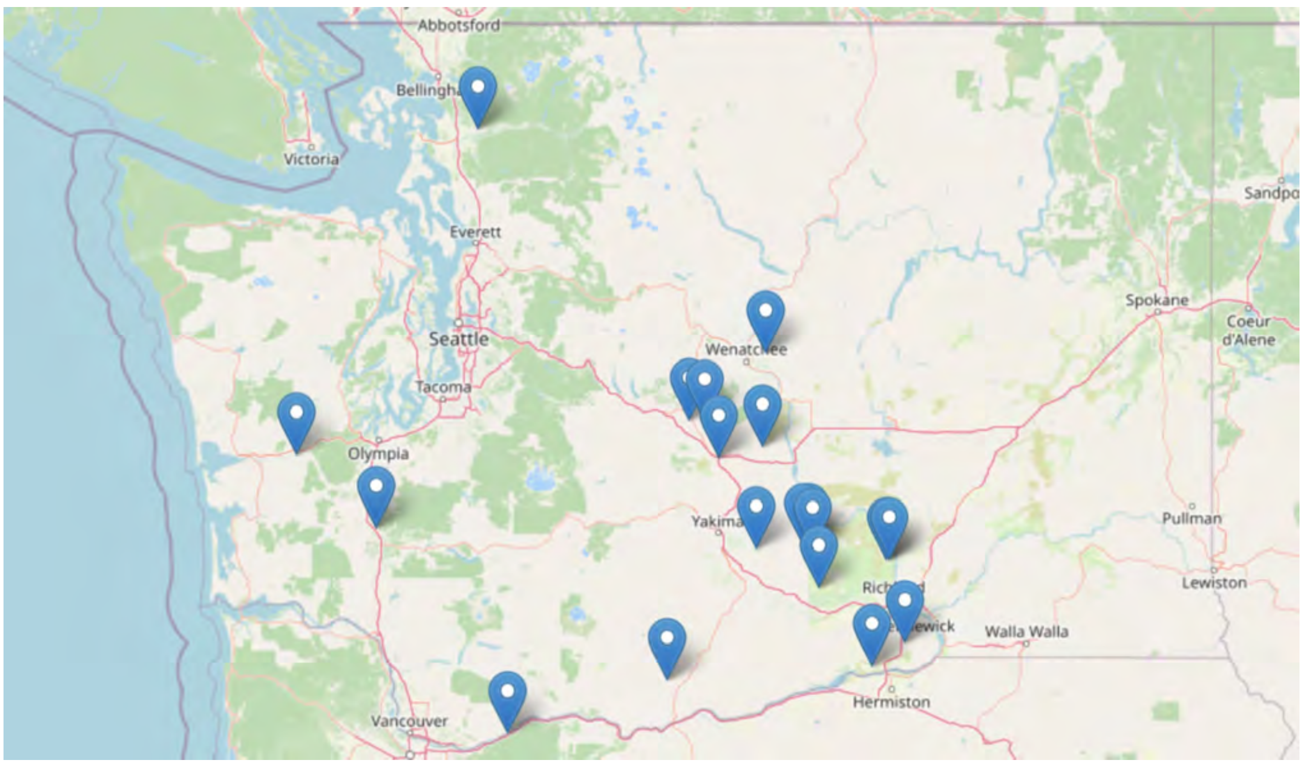


FIGURE 7. Energy facilities that have been approved or are currently moving through the EFSEC process[136]

136 EFSEC, "Facilities we oversee," (accessed Mar. 2026), https://efsec.wa.gov/.

5.2 Reform Early Outcomes

Washington's recent reforms are designed to reduce fragmentation by clarifying jurisdiction, aligning review steps, and creating more predictable decision calendars for large clean-energy projects. The reform package is anchored by House Bill (HB) 1812 (enacted in 2022) and HB 1216 (enacted in 2023), [137] along with programmatic environmental analysis undertaken by the Department of Ecology ("Ecology").[138]

In 2022, HB 1812 expanded EFSEC's jurisdiction, modernized its procedures, and established EFSEC as an independent state agency. The legislation authorized additional facility types—including clean energy product manufacturing, energy storage, and renewable or green electrolytic hydrogen—to opt into EFSEC's consolidated siting process, signaling a policy intent to make the statewide forum relevant to the technologies the transition now requires rather than leaving them to navigate fragmented approvals by default. HB 1812 also strengthened expectations for engagement with federally recognized Tribes, including by creating clearer roles for Tribal participation when a proposed facility implicates resources, rights, or interests reserved or protected by federal treaty, statute, or executive order. Those design changes expanded EFSEC's potential relevance, but they did not by themselves establish that the pathway had become faster or more predictable in practice. The early outcome so far has been more limited: Developers appear to be watching for evidence of improved throughput rather than migrating in masse into EFSEC, and recent examples suggest incremental performance improvement rather than a fully transformed forum. EFSEC has long been perceived by many developers as a path of last resort, but several major projects have reportedly moved from application to approval in roughly two to four years—still slow, yet somewhat better than prior expectations.[139]

137 Engrossed Second Substitute House Bill 1216 (WA 2023); Engrossed Second Substitute House Bill 1812 (WA 2022).
138 Ecology, "Programmatic environmental impact statements," (June 2025), https://ecology.wa.gov/regulations-permits/sepa/clean-energy/programmatic-eis.
139 Beveridge & Diamond, PC, "Siting and Permitting Reform in Washington"

GOVERNANCE CHALLENGES—HORSE HEAVEN WIND FARM

The Horse Heaven Wind Farm project in Benton County illustrates both the promise of statewide consolidation and the persistence of the most difficult governance challenge the reform must confront—culturally significant landscapes where impacts are not easily reduced to standard survey data. EFSEC's public project history shows the Council issued a final EIS on October 31, 2023, and Governor Inslee later approved a revised Site Certification Agreement on October 18, 2024 after remanding the project for additional work on cultural-resources and wildlife issues. The applicant signed the revised agreement on November 21, 2024. What followed underscores why finality is a core performance metric. The certification milestone did not end the dispute but instead transitioned the project into a new phase of appellate uncertainty. Consolidated challenges are now before the Washington Supreme Court, which has scheduled oral argument for June 11, 2026. Horse Heaven demonstrates that consolidation can force meaningful redesign, but it does not immunize decisions from challenge. The reform's success turns on whether determinative issues—especially treaty-reserved interests—are surfaced early enough that final decisions are not only timely, but durable under judicial scrutiny.[140]

The Carriger Solar Project in Klickitat County reinforces the pattern. Even though Carriger proceeded under EFSEC's streamlined solar application process and advanced under a mitigated determination rather than a full EIS, Governor Ferguson remanded the project in August 2025 for further engagement with the Yakama Nation after the Tribe's confidential Traditional Cultural Property study identified significant impacts that had not been fully addressed before EFSEC finalized its determination. The Governor later approved the revised draft Site Certification Agreement in December 2025, under considerable time pressure because federal clean-energy tax rules required construction to begin by July 4, 2026 to preserve the project's expected credit value, and the executed agreement followed later that month. On December 31, 2025, the Confederated Tribes and Bands of the Yakama Nation filed a petition for judicial review as well. Carriger demonstrates that even a streamlined process track does not eliminate the recurring consultation gap when cultural-resource concerns surface after key project assumptions have been set. It also exposed internal administrative dissonance: Klickitat County's EFSEC representative, Matt Chiles, submitted a formal dissent emphasizing the project's unanimous opposition from the county commissioners. The gubernatorial remand mechanism can force additional engagement, but it also adds schedule risk that is difficult to absorb when external financing deadlines are binding.[141]

140 EFSEC, "Horse Heaven Wind Project," (accessed Mar. 2026), https://efsec.wa.gov/facilities/horse-heaven-wind-project.

141 EFSEC, "Application review - Carriger Solar," (accessed Mar. 2026), https://efsec.wa.gov/facilities/carriger-solar/application-review?fid=109&tid=136.

TABLE 1. Comparison of Optional Pathways for Clean Energy Projects[142]

Actions and Roles	Ecology's Coordinated Clean Energy Permit Process	Energy Facility Site Evaluation (EFSEC) Council Process	Local Government-Led SEPA and Permitting Process
Applies to new projects or facility modifications	Yes	Yes	Yes
Agency coordinating overall process	Ecology coordinates the environmental review and permitting work with participating state and local agencies	EFSEC coordinates the environmental review and permitting work with participating state and local agencies	No single agency lead
SEPA lead agency	Determined based on project and location	SEPA review is incorporated into the EFSEC process and the EFSEC Director is the responsible official	Determined based on project and location
Permitting	Each of the project's permits has a state or local agency with legal responsibility	EFSEC makes decisions and issues most state and local permits as part of the Site Certification Agreement	Each of the project's permits has a state or local agency with legal responsibility
Decision-maker(s)	▶ For each permit, the agency responsible makes the decision ▶ All permits needed for a project must be approved	The EFSEC Council makes a recommendation to the governor, who makes the decision on a project	▶ For each permit, the agency responsible makes the decision ▶ All permits needed for a project must be approved
Responsibility for Tribal engagement and consultation	Ecology is responsible for offering Tribal engagement and consultation for the coordinated permit process	EFSEC is responsible, in coordination with Department of Archaeological and Historic Preservation (DAHP)	▶ State agencies would offer Tribal consultation for environmental reviews as the SEPA lead agency and/or for their permits ▶ Local governments can offer to engage with Tribes
Engagement with overburdened communities	Ecology verifies engagement has been done in timely manner and comments have been considered	EFSEC leads engagement	Each agency leads their own engagement process
Cost reimbursement required	Yes	Yes	May be required
Pre-application process	Yes	Yes (required for transmission lines)	Yes
Complete application required	Yes, it will be used for development of the work plan and to begin SEPA review	Yes, and if pre-application is done, the SEPA review can begin before the final application is submitted	Yes, it is used to begin SEPA review
Local ordinances	Local ordinances apply	EFSEC can preempt county and local ordinances	Local ordinances apply
Appeals	Permits each have their own requirements for appeals	Appeals are limited to the final decision and are not done for individual permits	Permits each have their own requirements for appeals

142 Ecology and EFSEC, "Focus on: Pathway options for environmental review and permitting clean energy projects," (Jan. 2024).

In 2023, HB 1216 addressed a critical pre-reform failure mode by creating the Clean Energy Coordinated Permitting Process (CPP) under Ecology and establishing an interagency coordinating council, co-chaired by the Departments of Ecology and Commerce.[143] CPP was designed to serve projects that do not enter EFSEC and would otherwise face a patchwork of permits without a single entity responsible for building a coherent schedule. Under this model, Ecology performs an early permit inventory, identifies sequencing and dependency risks, supports early Tribal and community engagement, and structures permitting work so that reviews proceed as concurrently as possible—while leaving each decision-maker's substantive authority intact and avoiding EFSEC-style preemption. For a comparison of the three permitting pathways, see Table 1 above.

The reform's programmatic environmental analysis effort responded to another pre-reform inefficiency: the tendency for SEPA to recreate baseline analysis for common technologies while site-specific disputes drove delay. Ecology released final programmatic environmental impact statements on June 30, 2025, covering utility-scale onshore wind, solar, and green hydrogen production and storage.144 These provide a common analytic foundation that project-level reviews can incorporate by reference, concentrating controversy and mitigation negotiation on site-specific constraints. For qualifying solar and wind facilities, SEPA lead agencies are now required to consider the PEISs in project-level review, giving the programmatic work a more formal role in narrowing recurring disputes than early reform commentary sometimes assumed. The programmatic analyses do not replace project-level SEPA determinations or permits; their value depends on whether lead agencies use them to narrow recurring disputes and make departures from baseline assumptions explicit where local conditions warrant heightened scrutiny.

Washington has also expanded the programmatic concept beyond generation technologies in a way that underscores how tightly siting performance is linked to grid deliverability and system planning. EFSEC released a separate Transmission Programmatic EIS on October 7, 2025, providing a high-level, statewide treatment of common impacts associated with high-voltage transmission development.[145] At the same time, Ecology is developing a programmatic EIS for sustainable aviation fuel, which Ecology's own timeline describes as slated for completion by June 30, 2027.[146] The through-line across these efforts is creating shared baselines that reduce redundant reinvention while preserving the legitimacy of site-specific analysis where impacts are uniquely local or culturally determinative.

Early reception of these programmatic tools remains mixed. Stakeholders described this programmatic approach as a necessary attempt to reduce reinvention and provide consistent baselines, but they emphasize that it is still too early to determine if these documents provide a full solution or merely incremental improvement. Further, they caution that without precise application, these broad documents may be vague enough to expand the scope of SEPA disputes—an implementation risk that could dilute intended time savings. The central tension is

143 Clean Energy Project Siting, ch. 230, Laws of 2023 (WA 2023).

144 Ecology, "Programmatic environmental impact statements," (June 2025), https://ecology.wa.gov/regulations-permits/sepa/clean-energy/programmatic-eis.

145 EFSEC, "Transmission Programmatic Environmental Impact Statement (EIS)," (accessed Mar. 2026), https://efsec.wa.gov/transmission-programmatic-environmental-impact-statement-eis

146 Ecology, "Scoping Document for Programmatic Environmental Impact Statement on Sustainable Aviation Fuel Production Pathways, Including Blending and Distribution Infrastructure, in Washington State," (Oct. 2025)

whether these shared baselines will sharpen project-specific decision-making or fail to account for the localized judgment calls that often determine legitimacy and litigation risk.

Early implementation of the coordinated pathway further raises legitimate questions about the added value of the Ecology-coordinated lane as a third pathway in a state that already has (1) local permitting and (2) EFSEC's consolidated option. Ecology describes CPP as combining pre-application discussions, SEPA environmental review, and coordinated state and local permits, with the state acting as a facilitator among developers, agencies, Tribes, and communities to identify risks early and maintain alignment across the permitting chain.[147] By contrast, some stakeholders characterize Ecology's role as closer to a coordination function—one that lacks primary permit authority and may therefore be limited in its ability to resolve the hard blocking issues that ultimately control schedule and finality. Because no coordinated projects have reached final decision points, the central evaluative question is whether earlier coordination consistently reduces late-stage reversals and rework and produces a record robust enough to withstand controversy and judicial review, rather than simply shifting effort into additional front-end process.

In sum, Washington has built new coordination institutions, expanded EFSEC to better match the clean-energy portfolio, and created statewide environmental baselines intended to reduce redundant SEPA work. The next performance test is whether these institutions and programmatic tools become operating practices that consistently clarify expectations early, integrate consultation and environmental review to reduce late-stage conflict, and protect final decisions from fragmentation—especially where cultural landscapes and environmental constraints make the stakes highest.

5.3 Identified Gaps and Bottlenecks

Early implementation of Washington's reform frameworks has revealed several gaps that, if unaddressed, risk hampering the state's ability to meet its climate commitments while maintaining environmental stewardship and social legitimacy. These gaps illustrate how delay becomes leverage and uncertainty becomes a governance outcome, allowing issues to remain open, contested, or serially re-litigated.

Layered Legal Regimes and Misaligned Sequencing: Clean energy facilities in Washington must satisfy overlapping state and local requirements—SEPA, land use plans and implementing ordinances, critical areas and shoreline rules, and an array of program-specific permits—while many projects also trigger federal approvals imposing NEPA compliance or other federal decision processes. This layering produces multiple gates that can dictate schedule, design, and even basic feasibility, and those gates are not consistently sequenced so that the most determinative constraints surface early enough to prevent rework. The gap is not too much review, but review that remains structurally vulnerable to late discovery and serial reopening because the system lacks dependable early alignment across sovereign and technical regimes.

147 Ecology, "Focus on: Clean Energy Coordinated Permit Process," (Sep. 2024).

Multi-agency Overlap and Diffusion of Accountability: Regulatory overlap within state government compounds baseline complexity by requiring developers to satisfy multiple agencies whose mandates intersect on the same facts while applying different statutory standards, technical methodologies, and enforcement cultures. This overlap generates duplication and process drift when no forum is empowered to treat early scope and methodology agreements as binding absent material new information.

Fragmentation also manifests as duplicative review and fee stacking when authority is split between state and local governments in ways that blur responsibility for outcomes. In a clean energy siting context, diffusion does more than slow projects: it weakens environmental performance governance by obscuring which decision points truly control outcomes, pushing developers toward defensive compliance strategies that privilege procedural completeness over early problem-solving.

Incoherent Front Door and Strategic Forum Selection: Washington now offers three pathways: a local permitting pathway whose speed depends on local political conditions and administrative capacity, EFSEC's consolidated and potentially preemptive pathway, and Ecology's coordinated pathway, which is designed to produce concurrency without preemption but remains widely viewed as unproven. This architecture appears to offer flexibility, yet in practice it rewards strategic behavior because pathway choice is meaningfully interchangeable for many facility types. Developers must choose a route early, often with imperfect information about which will be fastest or most successful.

Local permitting can be relatively fast in supportive jurisdictions but highly unstable in hostile ones, especially where moratoria, restrictive zoning, or discretionary conditional use standards signal a likely veto. EFSEC can preempt local barriers but is often perceived as slow and resource-intensive. Ecology's coordinated pathway aims to prevent serial, siloed decision-making, but its novelty has produced a wait-and-see posture among developers.

The state still lacks a legible default assignment grounded in objective triggers that would reduce incentives to treat forum selection as leverage and would push disputes into one schedule and one record early enough to stabilize expectations. Without that front-door clarity, both proponents and opponents have rational incentives to treat pathway selection as a strategy about leverage rather than as an administrative routing decision designed to optimize legitimacy and throughput.

Gatekeeping and Timeline Volatility: Timeline unpredictability remains a core problem even once a project enters a pathway, because nominal timeliness expectations often depend on gateway determinations that can be delayed without formally extending a statutory clock. EFSEC proceedings can take much longer than the one-year target when adjudication is extended and EIS development is iterative. Operational drivers of delay cut across pathways: the absence of timelines binding all decision-makers, uncertainty about mitigation requirements that may arise during review, and the quantity and duration of technical studies demanded before agencies close the record.

Completeness disputes can defer the point at which schedules meaningfully start. The systemic implication is that even faster tracks do not function as faster tracks when gatekeeping does not produce disciplined scope-setting and when foundational issues drift until redesign costs are highest.

Unclear Standards and Ad-hoc Mitigation Expectations: Procedural complexity interacts with a standards problem that becomes especially pronounced when legacy siting institutions are asked to govern modern renewables at scale. EFSEC's standards were developed around large fossil or nuclear facilities, and applying those institutional habits to wind, solar, and storage can create uncertainty about what is required for approval. Clear benchmarks for wildlife impacts, battery safety, and agricultural mitigation remain limited, meaning requirements are negotiated case-by-case through SEPA and the adjudicative record. Case-by-case negotiation produces moving targets: developers respond to one request only to face revised expectations later, while intervenors may hold issues for late leverage when redesign is most expensive.

The standards gap appears most sharply in mitigation and siting criteria, where Washington lacks uniform thresholds for common environmental and land-use issues. Disputes about mitigation for shrub-steppe habitat loss, turbine setbacks, and visual and noise impacts vary by county or agency, forcing debates to restart in each docket. Horse Heaven demonstrates how consequential this uncertainty can be, with disputes over raptor nest buffers, visual impacts, and cultural landscapes producing proposals ranging from turbine-free buffer zones to off-site habitat restoration. Programmatic EIS work can reduce redundancy, but a gap remains between publishing guidance and translating it into presumptive decision rules and safe-harbor design choices that are consistently applied.

Transmission and Interconnection Constraints: Transmission and interconnection constraints are a separate but deeply entangled gap because siting reform cannot deliver outcomes if approved generation remains stranded behind grid bottlenecks. Stakeholders frequently describe transmission as a more binding constraint than facility permitting itself because a fully permitted wind or solar project does not deliver clean power unless it can interconnect and obtain deliverable transmission service.[148]

Within Washington, bridging the east–west divide between renewable resource areas and Puget Sound load centers requires new transmission capacity, yet transmission lines often face even tougher siting battles than generation projects because of their large footprints and multi-jurisdictional crossings.[149] The BPA's role in operating significant portions of the high-voltage grid, combined with interconnection queue delays, constrained transfer capacity, and long lead times for upgrades, creates gating factors outside direct state control because they are shaped by federal processes and regional planning. This bottleneck feeds back into permitting by creating uncertainty about where projects can plug in and what upgrades will be required, which can stall facility review or force late redesign as interconnection realities change.

Local Opposition, Administrative Capacity, and Uneven Hosting Economics: Local opposition and jurisdictional conflict remain potent barriers. The state's best renewable resources are often located in rural eastern counties that do not align with the state's climate-focused political consensus. Counties retain powerful tools—zoning, discretionary approvals, moratoria,

148 Interagency Clean Energy Siting Coordinating Council, "Clean Energy Project Siting: Report to the Legislature," (Oct. 2025).
149 EFSEC, "Transmission Corridors Working Group: Final Report," (Aug. 2022).

restrictive ordinances, and comprehensive plan amendment processes. Even where the Legislature has limited certain local requirements, local governments still control land-use compatibility and can slow or block projects through other mechanisms.

Administrative capacity compounds these dynamics, as smaller counties may lack planning staff with expertise in utility-scale energy, leading to procedural delays, inconsistent application of standards, and legal vulnerabilities that invite appeal. Washington has begun to respond through technical assistance and grant support, including Commerce's Clean Energy Siting and Permitting grants program. Yet moratoria, discretionary conditional use structures, and layered appeals mean local conflict remains a determinant of timeline and outcome precisely in the regions where development pressure is intensifying.

Distributional conflict and hosting economics deepen these procedural dynamics. Some rural community members raise concerns that decisions lack transparency and are imposed without credible involvement or enforceable benefit frameworks, reinforcing skepticism about bearing local impacts for statewide benefits. Those concerns coexist with perspectives that projects can improve reliability, stabilize agricultural operations through lease revenue, and attract investment. The gap lies in the system's inconsistent ability to demonstrate—concretely and credibly—how decisions are made, how impacts are minimized, what benefits are delivered, and how local participation changes outcomes. When fiscal answers about project taxes and negotiated agreements are unclear or inconsistent, skepticism about hosting deepens.

Tribal Consultation Integration, Confidentiality, and Uneven Local Practice: Tribal and cultural resource uncertainty remains an unresolved gap because it implicates sovereignty, confidentiality, and landscapes whose significance is not reliably captured by conventional survey methods. As noted in Section 5.1, treaty-reserved rights extend into usual and accustomed territories that overlap with renewable and transmission corridors, and cultural resources are frequently intangible or confidential—a ridge, vista, or cultural landscape can be determinative without appearing in public databases.

Although reforms encourage earlier government-to-government consultation, implementation remains uneven, particularly in local processes where consultation expectations do not bind cities and counties. Cultural concerns can surface late after footprints and assumptions have hardened, and conflict can escalate quickly. A further gap lies in how consultation outcomes are integrated into decision rules: when a Tribe identifies impacts on treaty rights or culturally determinative landscapes, the regulatory schema does not always provide clear rules for how that input is weighed, leaving room for inconsistency and litigation. Consultation cannot function as late-stage participation if the goal is stable outcomes; it must be integrated early enough to influence design and siting choices.

Appeals, Judicial Review, and the Fragility of Finality: Permitting does not end at permit issuance when projects can be stalled for years through fragmented litigation. Washington has begun to acknowledge that post-decision delay can function as a second permitting timeline. EFSEC already routes appeals of the Governor's certification decision directly to the Washington Supreme Court, bypassing lower courts, while reforms for non-EFSEC projects have sought more direct appellate review routes. The design challenge is not to eliminate due process, but to preserve lawful review while preventing appellate structure from functioning as the primary instrument for stopping projects after the substantive record is closed.

5.4 Recommendations

Washington's reforms have laid a foundation for a more coordinated siting system, but the gaps identified above require targeted action to ensure the system performs as a delivery mechanism while maintaining legitimacy with Tribes and local communities. The recommendations below strengthen the reform architecture while making the tradeoffs explicit, so that speed is not purchased at the expense of due process, Tribal rights, or public trust.

Establish a Coherent Front Door and Objective Pathway Assignment: Washington still lacks a single, clearly defined front door that assigns projects to the appropriate pathway using objective criteria rather than political bargaining or jurisdictional ambiguity. Creating a primary intake and assignment function would reduce forum shopping and help communities understand, early, which decision body will be accountable. One approach would be to treat EFSEC as the default venue for projects above a specified MW threshold, for projects spanning multiple jurisdictions, or for projects requiring complex multi-agency coordination, with the CPP lane serving as a defined on-ramp for projects below that threshold. The design should pair centralization with explicit participation rights, predictable mitigation standards, and a transparent explanation of why a project qualifies for statewide treatment, so that the process does not operate as a jurisdictional end-run. To avoid creating a new bottleneck, resourcing, transparent criteria, and meaningful local and Tribal participation should be treated as prerequisites rather than optional add-ons.

Formalize Early Issue Identification and Binding Scoping: Washington should codify binding early scoping and closure mechanisms that require agencies to specify, within defined early windows, what studies are required, what mitigation will be treated as sufficient, and when the evidentiary record will be considered complete. This decision-forcing scoping reduces the risk that SEPA and related reviews become open-ended negotiation. Any closure mechanism should include a narrowly tailored reopener standard for genuinely new, material information, so that binding scoping does not lock in an incomplete picture or disadvantage communities and Tribes that need time to gather information.

In practice, the state could require that within a fixed period after application intake—such as 60 to 90 days—the lead agency convene agencies, Tribes, and key stakeholders to produce a scoping memorandum that lists required surveys, modeling, and mitigation concepts, identifies fatal-flaw issues, and sets a schedule for completion. Where government-to-government consultation implicates treaty rights or culturally significant landscapes, the schedule should allow a defined extension for meaningful Tribal input. Once the scoping memorandum is issued, later demands for new categories of analysis should meet a defined threshold—demonstrating that the issue could not reasonably have been identified earlier or that the project has materially changed. To prevent developers from exploiting these guardrails to rush incomplete filings, the state should pair scoping discipline with strong completeness standards and technical assistance for local governments and Tribes.

Translate Programmatic Analysis into Presumptive Standards and Safe Harbors: Washington can reduce variance by standardizing mitigation expectations for recurring issues—noise, setbacks, habitat impacts, and agricultural land protection—through rulemaking or programmatic analysis that creates clear performance standards. Where standard mitigation is appropriate, safe-harbor compliance should carry real weight by creating a presumption of sufficiency. Safe harbors must be coupled with site-specific waiver authority and clear criteria for when heightened mitigation is required, so that rigid standards do not under-protect ecologically or culturally sensitive sites.

Ecology's programmatic analysis provides a starting point: it identifies common impact pathways and mitigation measures broadly applicable to utility-scale solar, wind, and related infrastructure. To translate programmatic analysis into real predictability, Washington should convert key mitigation expectations into enforceable standards that agencies and local governments apply consistently, and publish model conditions that can be tailored but not reinvented case by case. To prevent programmatic documents from becoming shelf studies, standards should be tied to permitting triggers and agencies should be required to explain departures in writing, using evidence rather than preference.

Calibrate Adjudication and Streamline Appeals: Washington should constrain appeals and judicial review in ways that preserve due process while reducing incentives for strategic delay. Expedited review schedules, clear standing rules, and record-based review can shorten the long tail without eliminating accountability. Any streamlining should be paired with stronger record quality, clearer participation rights, and transparent reasoning so that speed does not undermine public trust.

Washington could adopt statutes requiring appeals to be filed within shorter windows, consolidated into a single forum, and resolved on an expedited schedule, while narrowing the scope of issues to those raised in the administrative record. The state could also limit serial appeals by requiring that all related claims be brought together. Because these limits could be perceived as restricting meaningful participation, the administrative process itself must ensure that issues can be raised early, addressed on the record, and resolved with clear findings.

Strengthen Tribal Consultation Framework and Capacity Support: Washington should strengthen mechanisms for early and well-resourced Tribal consultation, including clear expectations for confidentiality, data governance, and mitigation negotiation when treaty-reserved rights or culturally significant landscapes are implicated. Consultation that begins only after a project footprint hardens increases the likelihood that conflicts become zero-sum. Dedicated funding, staff support, and predictable consultation protocols are necessary to prevent enhanced consultation requirements from imposing unsustainable capacity burdens on Tribes.

This could include a state-funded consultation support program that provides resources for Tribes to review applications, conduct independent assessments, and participate meaningfully in hearings without diverting scarce governmental capacity. It could also include standardized consultation milestones tied to project phases, with clear rules about confidentiality protections in public dockets. These mechanisms should be defined as capacity and mitigation tools that protect rights and reduce litigation risk, not as substitutes for substantive evaluation.

Develop Transparent Community Benefit and Economic Reporting: Washington should require transparent, enforceable community-benefit reporting that distinguishes between modeled projections and verified outcomes and makes benefit commitments trackable over time. Benefit promises that are vague or unverifiable invite distrust and can convert siting hearings into proxy debates about fairness. Applicants should submit standardized benefit statements reporting expected and verified tax payments, lease payments, local contracting, and workforce participation, with third-party verification where feasible. The state should pair transparency with technical assistance and plain-language summaries that allow residents to understand what is promised and what is delivered.

Integrate Transmission Planning with Siting and Procurement: Interconnection and transmission constraints—and, for some projects, procurement—often appear more immediately constraining than generation siting timelines. Washington should pursue siting reform in coordination with grid planning, interconnection, and transmission development. The state can accelerate transmission planning and corridor identification, align that work with EFSEC's Transmission Programmatic EIS, and coordinate early with BPA, Tribes, landowners, and regional planning processes so that transmission is not treated as an afterthought to generation siting.

Monitor Performance, Collect Data and Adapt: Washington should invest in transparent performance metrics for its siting pathways, including standardized reporting of cycle times, completeness determinations, appeals outcomes, and post-permit compliance. Without measurement, stakeholders cannot assess whether reforms are working or whether delays are migrating to new stages. A public dashboard tracking key milestones, distinguishing agency time from applicant time, and reporting reasons for pauses would make the process legible and focus debates on substance rather than procedural mistrust.

5.5 Conclusion

Washington's reform experience illustrates that the core siting challenge is the interaction of legal authority, record-building, consultation, and deliverability in a system now asked to process more infrastructure, faster, under higher scrutiny. The reforms move in the right direction by expanding consolidated pathways and creating a coordinated permitting lane, but the evidence base is still early. The most contentious cases—especially those implicating treaty-reserved rights or culturally significant landscapes—may remain resistant to purely procedural solutions, which is why reform success should be evaluated separately for routine projects and the long-tail disputes that set public narratives.

The coordinated pathway and programmatic analysis can reduce variance by clarifying permit inventories, aligning agency sequencing, and standardizing mitigation expectations, while EFSEC can reduce fragmentation by providing a single forum capable of issuing a closure-grade record. Yet neither tool automatically resolves the remaining weaknesses. Washington's next phase of reform should prioritize mechanisms that convert early engagement into binding clarity: objective front-door criteria, enforceable scoping and closure, and performance metrics that track not only permit issuance but post-permit deliverability.

Washington's experience also underscores that legitimacy is not a secondary concern that can be addressed after the fact. Mistrust drives opposition, litigation, and political backlash. Benefit frameworks, workforce linkage, and Tribal consultation protocols must be part of permitting design rather than optional add-ons—designed to reduce late-stage conflict rather than becoming an unbound front-end burden.

The remaining gap is the distance between an improved statutory framework and a fully operational, predictable delivery pipeline. If clean resources and transmission cannot be permitted and interconnected on a workable timeline, the state risks greater pressure for fallback reliability measures. Closing that gap requires treating siting, transmission, interconnection, and community legitimacy as a single system with shared bottlenecks rather than as separate policy silos. If Washington can do that, it will reduce controversy and wasted effort, lower litigation risk, and make both approvals and denials more timely, transparent, and durable.

6 CROSS-STATE SYNTHESIS

California, Illinois, New York, and Washington adopted different institutional responses to the same basic problem. Although the track record is still emerging, their early experiences point to a common lesson: permitting reform succeeds less because a statute announces shorter timelines or reallocates authority, and more because the process resolves consequential issues early, reduces fragmented decision-making, and produces approvals that remain durable through implementation. The comparison does not turn on a simple centralized-versus-hybrid reform model distinction. It turns on whether the reform creates real closure before conflict reappears in another form.

All four reforms improved some part of the siting process, and projects that previously would have faced greater local obstruction are now more likely to advance. However, formal acceleration alone does not determine whether projects are built on time. What matters more is whether the process forces major disputes to surface while project design is still flexible, integrates the approvals that determine viability, and preserves the integrity of the final decision long enough for the project to be financed, constructed, and connected.

Delay, however, often shifted rather than disappeared. Reform frequently narrowed one bottleneck only for conflict to reappear elsewhere. Where local veto power was reduced, disputes migrated into pre-application requirements, completeness review, permit conditions, post-approval compliance, fee demands, or road-use agreements. Where formal decision clocks shortened, more pressure fell on pre-filing procedures, intake, and the determination of when the clock actually starts. Where state review centralized, unresolved issues resurfaced in retained permits, litigation, or implementation-stage requirements. The central empirical lesson is not that some reforms are faster than others, but that permitting processes underperform when they relocate uncertainty rather than resolve it.

This pattern makes the front end of the process one of the most consequential features of the comparison. Once statutes impose binding deadlines, the point at which an application is deemed complete effectively determines whether those deadlines measure the true duration of development or only the last portion of a longer negotiation. The reforms that performed more predictably did more work early: clarifying study requirements, surfacing material conflicts before the record hardened, and narrowing the range of issues that could reopen later. Where completeness standards were elastic or inconsistently applied, formal deadlines did less to reduce uncertainty than to conceal where the real delay had moved. Predictable permitting thus depends as much on disciplined pre-application procedures, scoping, and early consultation as on the decision clock itself.

Statutory design and implementation architecture also work together. The statutes studied here differ in important ways, and many recurring obstacles are practical rather than purely legal—uneven local capacity, poor interagency coordination, and unclear procedural expectations. However, those implementation challenges are often shaped by the way the process was designed. A process that leaves environmental review unresolved, treats completeness as elastic, preserves broad hearing standards, or adds timelines without narrowing the issues that can reopen later will place even well-intentioned administrators in a persistently difficult position. The key policy question is therefore not only what rules a state adopts, but whether those rules address the underlying drivers of delay and can be administered under real-world conditions. A reform that looks strong on paper will still depend on adequate resources, working coordination mechanisms, clear applicant expectations, and participation early enough to shape design. The strongest reforms are those in which statutory language and administrative practice reinforce one another, resolving the issues that actually generate delay rather than accelerating the calendar around them.

The reforms also confirm that preemption and consolidation, while important, are not self-executing. Reassigning authority reduces formal local veto power but does not eliminate conflict if material decisions remain outside the main approval pathway or if affected communities distrust the institutions making those decisions. Across all four states, opposition persisted through litigation, procedural tactics, political pressure, and post-approval disputes even where state authority had expanded. The relevant question is not whether authority sits at the state or local level, but whether the process channels conflict into a bounded forum early enough to be resolved without reopening the project later.

Legitimacy must accordingly be treated as part of permitting performance, not as a separate concern. Opposition was shaped not only by formal legal authority but by whether communities, local officials, and Tribes believed their concerns could credibly influence outcomes. These conflicts often involve credible concerns about environmental harm, procedural fairness, local autonomy, cultural resources, land-use identity, and the distribution of costs and benefits—they cannot be reduced to "NIMBY" resistance or bad information. No siting process can eliminate all controversy, particularly for land-intensive infrastructure whose visible costs concentrate in host communities while benefits are regional or statewide. Host-community benefits can be important, but they are not a substitute for early efforts to avoid, minimize, and mitigate impacts, or for engagement that occurs early enough to shape project design.

Durable permitting processes therefore require structured engagement early enough to affect design, clear expectations about mitigation and benefit frameworks, and sufficient institutional support for communities and Tribes to participate as meaningful actors—so that conflict does not migrate into contested completeness, escalating hearing demands, litigation, moratoria, or political rollback. Meaningful community engagement is part of the architecture that prevents permitting processes from becoming vehicles for translating unresolved conflict into delay.

Political feasibility and institutional history also shape reform architecture. States rarely build an ideal framework from scratch; they must assemble reform within inherited distributions of local authority, legislative history, environmental review traditions, agency turf, and the coalitions required to enact change. Incremental fixes may be the only viable near-term step, yet incrementalism that leaves core failure modes intact predictably requires further iteration. In practice, compromise frequently relocates conflict to the remaining seams, forcing policymakers back to the drawing board—not as an anomaly, but as a predictable feature of reforming systems whose legal and institutional histories continue to shape how new processes function.

Most fundamentally, a permit that cannot be financed on a predictable schedule, defended against legal challenge, or connected to the grid does not meaningfully advance reliability, affordability, or energy policy goals. This is why New York's stronger throughput is significant but not sufficient, why Illinois's gains remain contingent on enforcement and implementation, and why California and Washington reveal the continuing importance of sequencing, closure, and grid alignment even where reform has been substantial. The relevant endpoint is not administrative approval alone; it is a durable path from proposal to operation.

The four cases do not identify one ideal institutional model. They identify a recurring set of institutional seams: unclear front-end routing, elastic completeness review, partial consolidation, open-ended post-approval obligations, fragmented dispute resolution, weak engagement structures, uneven implementation capacity, and persistent disconnection between permitting and grid deliverability. These recurring seams are the real comparative findings of this report—showing where current reforms remain incomplete and why second-generation reform must focus less on abstract debates over state versus local control and more on the concrete design features that determine whether a permit becomes a buildable project.

7 PRINCIPLES FOR STATE SITING AND PERMITTING REFORM 2.0

The comparative evidence supports a set of design principles for second-generation state-level siting reform. These principles are not a blueprint for a single institutional model. States differ in legal history, environmental review traditions, administrative capacity, and political feasibility, and no one-size-fits-all structure will be appropriate in every context. The more transferable lesson is functional: successful reform requires that certain core tasks be performed somewhere in the process, by institutions with sufficient authority, clarity, and accountability to perform them well. The principles below are therefore best understood as the building elements of successful reform. States may combine the principles below differently depending on their circumstances, but predictable and durable outcomes are most likely when they are assembled coherently and made to reinforce one another.

Front-End Gating and Scope Control

1. **Replace Venue Shopping with a Coherent Front Door:** Similarly situated projects should enter one primary pathway based on objective triggers such as project size, geography, technology, or the number of jurisdictions implicated. When applicants can choose among forums with different standards, procedures, or timelines, conflict migrates rather than resolves.

2. **Structured Pre-Application Engagement:** Major adverse impacts and conflicts should be surfaced before the formal application is filed. Early engagement with Tribes, local governments, relevant agencies, and host communities should be structured to identify material environmental, cultural, and land-use conflicts while project design is still flexible enough to respond. That phase should be organized around the hierarchy of avoid, minimize, and mitigate potential significant adverse impacts to the maximum extent practicable. Its purpose is not merely to gather data and comments, but to identify which impacts can be avoided altogether, which can be minimized through redesign, and which must ultimately be mitigated if the project proceeds.

3. **Use Technology-Specific Application Requirements and Study Protocols:** Solar, land-based wind, and storage projects present recurring, increasingly well-understood impact profiles, and modern permitting systems should not treat them as though regulators are seeing them for the first time. States should adopt technology-specific application requirements, survey protocols, modeling standards, and filing expectations that reflect what is already known about recurring impacts. Doing so improves predictability, reduces iterative data requests, and helps all participants understand what a decision-ready application must contain.

4. **Bind Scoping Early and Make Completeness a Clearly Defined Gate:** Completeness should be determined against defined application requirements and filing protocols established in advance. It should not function as a negotiated threshold that shifts with reviewer discretion, political context, or applicant sophistication. Where scoping expectations remain open-ended, the pre-clock becomes the real schedule, and statutory deadlines lose much of their practical value. A disciplined completeness gate keeps Day 0 from becoming an elastic and opaque source of delay.

5. **Develop Uniform Statewide Standards and Define Waiver Rules with Precision:** A baseline of predictable statewide standards reduces patchwork subjectivity and limits the ability of local restrictions to function as arbitrary exclusions. Where local requirements can be waived or displaced, the governing criteria should be transparent, evidence-based, and publicly intelligible. Predictability depends not only on having statewide rules, but on making clear when deviation is permitted, on what grounds, and by whom.

Integration and Finality

6. **Modernize Environmental Review and Convert Recurring Issues into Presumptive Standards:** States should modernize environmental review by using regulatory exemptions where legally appropriate, programmatic or functionally equivalent review pathways, and tiered review to address recurring categories of impact. These tools should be used to

establish safe-harbor design practices and presumptive mitigation measures for recurring issues such as farmland conversion, wildlife interactions, wetlands, stormwater management, routine construction effects, and common storage-related impacts. This narrows project-level disputes to genuinely site-specific issues and reduces the need to recreate the same foundational analysis in every docket.

7. **Design Decisions for Delivery, not Simply Conditional Approval:** The central objective should be a decision that is commercially usable, legally durable, and aligned with deliverability. To the greatest extent legally feasible, material determinations should be pulled into the same decisional moment rather than left to open-ended post-approval processes that can still alter cost, design, or sequencing after the headline vote. A permitting process succeeds when approval remains valuable long enough to become a built and operating project.

8. **Treat Community Acceptance as Infrastructure Planning:** Engagement with Tribes, local governments, host communities, and affected agencies should begin early enough to influence project design while flexibility still exists. Intervenor funding, municipal technical assistance, transparent process mapping, and clearly defined consultation expectations are not optional courtesy measures. They are practical tools for reducing long-tail variance and preventing conflict from hardening into redesign, delay, or litigation. Durable reform requires institutions that affected communities regard as credible, not merely fast.

9. **Write Statutes to Operate, not to Signal Intent:** Completeness rules, fee ceilings, hearing scope, decision deadlines, and post-permit condition requirements must be written as enforceable operating commands rather than as broad statements of aspiration. Ambiguity invites strategic delay and widens the gap between legislative intent and administrative reality. Model ordinances, standardized application materials, and clear procedural protocols help make reform workable across jurisdictions with very different levels of capacity and experience.

10. **Build a True One-Stop Decision, not Merely a Permit Hub:** Coordination is valuable, but coordination alone is not closure. The strongest systems do more than inventory permits or sequence parallel reviews; they ensure that the approvals most likely to determine project viability are synchronized to the same schedule and resolved in a way that prevents later-moving processes from undoing the main decision. Where legal constraints prevent full consolidation, the state should still minimize the number of material issues left to separate timelines and clearly define how retained approvals will interact with the principal decision.

Legitimacy and Implementation Capacity

11. **Back Decision Clocks with Real Consequences:** Deadlines matter only when institutions face consequences for missing them. Automatic completeness findings, mandatory decisional timeframes, or other defined procedural consequences create incentives to resolve disputes early rather than carry them indefinitely. A clock without consequences is little more than a statement of preference.

12. **Design Hearings around Outcome-Determinative Issues:** Adjudication should be bounded to disputes that could plausibly change the final decision. The threshold for formal hearing

should be clear enough to preserve due process while preventing routine reopening of settled methodologies, generalized opposition, or issues already addressed through programmatic standards or earlier scoping. The aim is not fewer hearings for their own sake, but hearing structures that focus on questions genuinely requiring formal resolution.

13. **Consolidate and Clock Appeals:** Challenges should move to a single appellate forum on an expedited, record-based schedule. Parallel or sequential litigation tracks that continue for years after certification are among the most damaging sources of commercial uncertainty, especially once projects have made major financial commitments. A permit remains fragile so long as review is fragmented across venues or untethered to predictable timelines.

14. **Synchronize Interagency and Inter-Sovereign Inputs to the Permit Clock:** Environmental agencies, agricultural agencies, cultural resource authorities, and Tribal governments should be treated as early design participants rather than late-stage commenters. Where treaty rights or government-to-government obligations apply, meaningful early consultation is a throughput strategy as much as a legal requirement. Late consultation is more likely to produce remand, redesign, or both. Systems perform best when these inputs are synchronized to the same schedule and treated as central to closure rather than as parallel processes.

15. **Build Capacity Where the System Depends on It:** If reform relies on local review, local participation, or hybrid administration, then states must treat capacity as a core part of the architecture. Local governments need staff, technical assistance, model forms, and realistic timelines. Tribes and community participants need sufficient resources to engage early and effectively. Agencies need internal mechanisms to coordinate specialized expertise across environmental, cultural, agricultural, and safety issues. Capacity support is not ancillary to reform. It is one of the conditions that makes reform operable.

Delivery Alignment Beyond Permit Issuance

16. **Build Post-Approval Accountability into the Architecture:** Monitoring, complaint intake, enforcement visibility, decommissioning compliance, ownership-transfer oversight, and other forms of follow-through should be built into the process from the outset in forms that are transparent, durable, and enforceable over the life of the project. Weak enforcement credibility invites stakeholders to front-load conflict into siting because that is when leverage is greatest. Durable reform requires not only faster decisions, but confidence that what is promised during permitting will be carried through in practice.

17. **Structure Host-Community Benefits as Part of a Broader Impact Framework:** Community benefits are most stabilizing when they are transparent, durable, and enforceable, but they should not be treated as a substitute for good siting or early conflict reduction. The first priority should be to avoid, minimize, and mitigate project impacts to the greatest extent practicable. Benefits should then be structured as a complementary part of the overall framework, with clear reporting, follow-through, and accountability. Flexible benefit design remains important, but flexibility should not come at the expense of transparency or enforceability.

18. **Align Siting with Grid Deliverability and System Planning:** Siting, interconnection, transmission, and procurement should be treated as linked components of one delivery system. Reform that accelerates siting while leaving interconnection and transmission unstable merely shifts risk downstream and produces paper approvals rather than operating assets. Performance should be measured not by permits issued, but by permit-to-operation conversion. States should design permitting systems with grid readiness in view so that procedural speed translates into actual infrastructure delivery.

19. **Make the Reform Self-Correcting through Institutionalized Performance Review:** Because siting reform is governance redesign rather than a one-time statutory event, states benefit from institutionalizing a structured performance review cycle. Such a cycle should evaluate where time is actually being spent—completeness, contested issues, post-permit compliance—how often jurisdictional disputes arise, and whether siting outcomes align with interconnection deliverability. Publishing this data transparently allows policymakers, developers, and communities to identify emerging bottlenecks before they become entrenched and to calibrate reform iteratively rather than waiting for the next legislative window. A metric-driven review cycle converts reform from a static statutory product into an adaptive governance system.

These principles point toward a more disciplined model of siting reform. The core task is not to speed review or move authority from one level of government to another, but to design a process that resolves the issues most likely to generate delay, does so early enough to preserve meaningful flexibility, and carries those resolutions forward in a form that is legally durable, administratively workable, and publicly credible. Second-generation reform should be judged not by whether it produces shorter timelines on paper, but by whether it produces decisions that remain buildable, enforceable, and legitimate through operation.

8 CONCLUSION

Permitting reform has shifted from an aspirational policy goal to a structural requirement of energy governance. The question is no longer whether states should modernize siting and permitting processes, but whether those reforms can produce approvals that translate into operating projects. The evidence in this report shows that slowness is not the sole failure mode; delay and conflict migrate to whatever part of the process remains least bounded. A permit that triggers redesign, invites years of downstream challenge, or cannot be financed, interconnected, and built on a workable schedule has not achieved closure. Permitting must be understood as part of a delivery system, not a discrete administrative exercise—producing decisions that are financeable, legally durable, commercially usable, and legitimate enough to withstand political and opposition scrutiny.

Because legal frameworks, administrative capacity, and political feasibility vary across jurisdictions, there is no universal blueprint for reform. The design principles outlined here offer guidance on how to surface determinative issues early, discipline scope, and carry resolutions forward, but they must be adapted to local context. The common denominator is the need to align permitting with deliverability—integrating approvals with interconnection, transmission, procurement, and community engagement so that projects move from paper to operation within timelines consistent with reliability, affordability, and energy policy goals.

Incremental change is often the only practical path, given existing institutions and the compromises required to enact legislation. Partial fixes can produce meaningful progress, but they are waypoints rather than endpoints. Their value depends on whether policymakers recognize the seams that remain and treat them as the agenda for the next round of reform. Where those seams are left open, the process will continue to cycle through procedural adaptation, renewed conflict, and further legislative or administrative overhaul—not because the original reforms failed in concept, but because implementation surfaced what the statute left unresolved.

The most transferable lesson is not a specific model to copy, but a diagnostic to apply: does a state's siting regime reliably convert a proposal into a buildable, defensible, and socially durable project? If not, identifying the institutional seam responsible becomes the priority for the next reform. Success comes not from shortening a single step or shifting authority, but from building a process capable of closing uncertainty early enough to enable investment, withstand scrutiny, and deliver the infrastructure the United States needs.

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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in state regulation, transmission planning, and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

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