CENTER FOR CLIMATE AND ENERGY SOLUTIONS

Comprehensive Summary of the Bipartisan American Affordability and Jobs Act

This document provides a comprehensive contextual bill summary of the Bipartisan American Affordability and Jobs Act of 2026 (BAAJA, S.5653), introduced by Sens. Shelley Moore Capito (R-W.Va.), Mike Lee (R-Utah), Sheldon Whitehouse (D-R.I.) and Martin Heinrich (D-N.M.) on September 30, 2026, and updated to reflect the manager's amendments, released on November 7, 2026, to substitute the Survivor Justice Tax Prevention Act (H.R. 2347).

C2ES has produced this summary, incorporating the manager's amendment, to provide an explanation of BAAJA and how it could affect federal permitting and infrastructure development. For selected provisions, the summary provides additional context on existing law and processes, the significance of the proposed changes, and their potential benefits, drawbacks, and broader implications. It also includes a separate "Manager's Amendment" paragraph identifying the specific changes made to each section.

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Division A—Committee on Environment and Public Works

Title I—National Environmental Policy Act of 1969

Subtitle A—Declaration of Environmental Policy

Section 1101. Purposes; procedure; savings provision.

Summary: This section would clarify the role of the National Environmental Policy Act (NEPA) as a statute that establishes a procedure for agencies to evaluate and inform the public about the reasonably foreseeable environmental effects of major federal actions. Major federal actions are actions taken by an agency that are subject to substantial federal control and responsibility, for example, granting a right-of-way across federal land for a transmission line; the definition excludes certain nonfederal projects with minimal federal funding or involvement. This section also states that NEPA is intended to inform federal decision-making and does not require agencies to choose a particular environmental outcome.

Context: This provision would reinforce in statute the legal understanding of NEPA as a procedural law. Before a federal agency takes or approves certain actions, it must consider the potential environmental consequences and, where required, reasonable alternatives. The level of review varies depending on the project: actions that normally do not have significant environmental effects may qualify for a categorical exclusion; projects with uncertain effects may require an environmental assessment (EA); and projects expected to have significant effects require the more detailed environmental impact statement (EIS). NEPA is intended to ensure that agencies and the public understand those effects before decisions are made, but it does not require an agency to choose the option with the least environmental impact identified in an EA or EIS.

Section 1102. Definitions.

Summary: This section would expand NEPA's statutory definitions, including several terms that determine when agency action requires a NEPA review and the scope of that review. The following are some of the notable changes and are not an exhaustive list:

Authorization: This section would create a statutory definition of authorization; a term used in legislative text but not currently defined in NEPA's definitions section. Under this definition, an authorization would be any federal administrative decision or interagency consultation required or authorized under federal law to implement a proposed agency

action, including leases, rights-of-way, easements, licenses, permits, approvals, findings, and determinations.

Categorical exclusion: A categorical exclusion identifies a set of actions that normally do not significantly affect the human environment and therefore do not require preparation of an EA or EIS. Current law defines these as categories identified by federal agencies. This section would expand the definition to also include categories of actions that Congress designates as categorical exclusions by statute.

Major Federal Action: This section would add specific exclusions to the current definition of major federal action, such as maintenance of federal facilities costing no more than $10 million, qualifying federally assisted broadband projects in a previously analyzed right-of-way, and proposed agency actions that previously underwent NEPA review by another agency. The section also clarifies that projects financed by the Transportation Infrastructure Finance and Innovation Act or Railroad Rehabilitation and Improvement Financing programs would not qualify for the exclusion based solely on federal involvement through loans or loan guarantees, and that projects funded by the Department of Transportation would not be excluded unless the federal cost share is less than $10 million.

Record of stakeholder engagement: This section would create a new statutory definition of record of stakeholder engagement, defined as a document that summarizes a project sponsor's preapplication engagement with federal, state, local, Tribal, and community stakeholders, including key feedback and how it was incorporated into the project. While the provision would require a record of engagement that occurred, it would not itself require the project sponsor to engage with every potentially affected stakeholder.

Section 1103. Implementing procedures.

Summary: This section would require every federal agency to revise its regulations, guidance documents, procedures, or policies as needed to implement this title. The Chair of the Council on Environmental Quality (CEQ), referred to as the Chairman in this bill and throughout this summary, would work to standardize agency procedures to the maximum extent practicable and could provide agencies with technical assistance. CEQ is the White House entity responsible for coordinating and providing governmentwide guidance on NEPA.

Section 1104. Cooperation of agencies; reports; availability of information; recommendations; international and national coordination of efforts.

Summary: This section would require agencies to develop methods for considering environmental values that are consistent with the requirements for minimum functional and data and technology standards for agency implementation of eNEPA technologies, meaning digital tools used for environmental reviews and permitting.

Section 1105. Procedure for determination of level of review.

Summary: This section would expand the circumstances in which an agency may determine whether a proposed action requires the preparation of an environmental document (i.e., an EA or EIS).

Under this section, a proposed action could qualify for one or more categorical exclusions, whereas current law is written in terms of a single categorical exclusion. However, an agency could not repeatedly apply the same or similar exclusions for environmental review that are based on size, acreage, or dollar thresholds for the same proposed action. This limitation is intended to prevent agencies from stacking threshold-based exclusions to avoid preparing an EA or EIS for an action that exceeds the relevant threshold. The provision would also expressly recognize categorical exclusions established by Congress.

An environmental document would also not be required if the lead agency determines that a state or Tribal environmental review serves a similar function as NEPA compliance, or that compliance with another federal law serves a similar function for the action. This section would allow the project sponsor to ask the lead agency to stop the preparation of an EA and proceed directly to an EIS.

If the lead agency determines that no environmental document is required, no other federal agencies could prepare their own environmental document for the same proposed action.

Context: These changes could reduce duplicative environmental review and would allow projects to move more quickly through the permitting process when another review process or existing categorical exclusion already addresses the relevant environmental issues. The changes would also give the lead agency greater control over whether an additional environmental document is required, which could provide more consistency and certainty across multiagency projects.

Section 1106. Timely and unified Federal reviews.

Summary: This section would strengthen coordination of federal environmental reviews by clarifying the responsibilities of lead and cooperating agencies, establishing additional permitting deadlines, and creating new mechanisms to resolve interagency disputes and enforce deadlines.

Lead agency

A lead agency is the federal, state, or Tribal agency primarily responsible for managing and coordinating the NEPA review when multiple agencies are involved. The bill would retain the existing criteria for determining which agency serves as lead but would shorten the process for resolving disagreements over that designation.

This section would also expand the lead agency's responsibilities by expressly granting it the authority to define and determine the project's purpose and need, reasonable alternatives, and reasonably foreseeable environmental effects within its jurisdiction. In a NEPA review, "alternatives" are other ways of accomplishing the proposed agency action's purpose and need, while the "no-action alternative" considers what would happen if the action was not taken. This section prevents the lead agency from considering alternatives, other than the no-action alternative, that do not fulfill the proposed agency action's purpose and need or the goals of a project sponsor. For

projects initiated by a Tribe involving Tribal trust resources, the lead agency would presume that the no-action alternative has negative effects.

If an environmental document or authorization is at risk of missing deadlines set by the project schedule, the lead agency would notify the Chairman of the reason for the potential delay.

Cooperating agencies

This section would limit cooperating-agency designation to agencies with jurisdiction by law and would establish deadlines for identifying and inviting cooperating agencies, accepting or declining an invitation, and bringing in agencies that were initially overlooked.

Cooperating-agency comments on the environmental review would be limited to matters within that agency's jurisdiction, including environmental effects and authorizations for which it is responsible. Cooperating agencies would be bound by the lead agency's purpose and need and could consider only alternatives the lead agency determines are reasonable, although they could assist in preparing the environmental document with the lead agency's agreement.

Coordinated reviews

To the maximum extent possible, agencies would conduct their respective reviews, authorizations, and federally required comments on environmental documents concurrently and establish procedures to keep the overall process coordinated and on schedule, unless the lead or cooperating agency, as applicable, determines that concurrent work would impair its ability to fulfill its statutory obligations.

Scientific information

This section would provide that agencies are not required to consider scientific or technical research that becomes publicly available after the notice of intent or decision to prepare the environmental document. Agencies also could not delay an environmental document or authorization beyond its deadline while waiting for federally required agency comments or new research or information that was not yet available. However, this section would preserve applicable requirements under the Administrative Procedure Act concerning review of information received during public comment.

Public participation

This section would establish a 45- to 60-day public comment period following publication of a notice of intent to prepare an environmental impact statement in the Federal Register. The comment period would allow the public to provide input on potential alternatives, environmental impacts, and relevant information, studies, or analyses related to the proposed agency action. The lead agency and project sponsor could agree to extend the comment period, up to a maximum of 75 days.

Existing documents

At the project sponsor's request, the lead agency would also have to consider and, where appropriate, adopt, tier to, or incorporate analysis prepared for the same or a similar agency action under federal law or state or Tribal environmental-review processes that serve a similar function as NEPA. Tiering would allow a review to build on earlier analysis rather than repeat it.

Review and permitting deadlines

This section would create deadlines for issuing a record of decision and for completing outstanding permits and authorizations. After an EA or EIS is completed and made public, participating federal agencies would have 90 days to decide outstanding permits and authorizations, while other federal agencies would have 120 days. After completing an EA, the lead agency would have seven days to issue a finding of no significant impact or publish a notice of intent to prepare an EIS. After publishing an EIS, the lead agency would have 45 days to issue a record of decision.

This section also builds on CEQ's existing role in resolving interagency disputes by establishing a more specific process for project sponsors to elevate delays or disagreements that threaten applicable deadlines, including federally required agency comments on environmental documents. The bill would set deadlines for CEQ to resolve those disputes, allow the Chairman to issue a binding determination if necessary, and create consequences when agencies fail to comply or continue to miss permitting deadlines. Those consequences could include requiring certain senior agency officials to spend at least 50 percent of their workweek addressing the delay and restricting official travel by the head of the agency until the agency comes back into compliance. The Chairman's dispute-resolution order would be final and not subject to judicial review.

It would also strengthen judicial enforcement of permitting deadlines by establishing a specific process for project sponsors to seek expedited court review when an agency fails to act on time, subject to limited circumstances that may excuse the delay. Where no statute provides exclusive appellate review of the authorization, the sponsor could file in the district where a substantial part of the action is situated or in the U.S. District Court for the District of Columbia.

Agency oversight and reporting

This section would require agency heads to submit annual reports on deadline performance to the Chairman, including information on missed deadlines for environmental documents, reviews begun before the Fiscal Responsibility Act of 2023 that remain incomplete, each key permitting agency's on-time completion rate, and its progress compared with the previous year.

The Chairman would then compile the agency reports, make recommendations for improving agency performance, and submit the consolidated report and recommendations to the House Committee on Natural Resources and the Senate Committee on Environment and Public Works.

Context: Federal environmental reviews and related permitting can take years to complete, particularly where a project requires approvals from several agencies.

Current law already provides for a lead agency, cooperating agencies, coordinated environmental reviews, and one- and two-year deadlines for EAs and EISs, respectively. This section would strengthen that existing framework by giving lead agencies more authority to coordinate reviews and manage deadlines. For projects that require approvals from several federal agencies, that change could reduce duplication, conflicting demands, and delays caused by agencies working on different timelines or reopening issues late in the process.

This section could also make overall project schedules more predictable by establishing enforceable timelines for permits and other federal authorizations beyond the environmental review itself. Compared with current law, project sponsors would have clearer mechanisms to address interagency delays and enforce missed deadlines, which could make project schedules more predictable and reduce prolonged permitting uncertainty.

The new limits on consideration of later scientific and technical information could also help prevent reviews from being prolonged by information introduced late in the process. A more stable administrative record could help agencies complete reviews on a predictable schedule and give project developers and investors greater confidence about when the process will conclude, which could help financing, investment, and construction planning decisions. However, limiting the consideration of new information could also prevent agencies from incorporating relevant scientific findings or newly identified environmental impacts that emerge during a lengthy review.

Manager's amendment: The changes would clarify that federal agencies should carry out federally required comments on environmental documents concurrently with other environmental reviews and authorizations, unless the lead or cooperating agency determines that doing so would impair its ability to fulfill its statutory obligations. It also would prohibit agencies from delaying environmental documents or authorizations beyond applicable deadlines while awaiting those comments. The manager's amendment would expand provisions allowing lead agencies to use existing environmental analyses by expressly permitting them to tier to earlier analyses and consider documentation prepared under federal law or for similar proposed agency actions. It would also expand the interagency dispute-resolution process to cover delays or disagreements involving the preparation of environmental documents and federally required agency comments. Finally, it would clarify that project sponsors may seek judicial enforcement of permitting deadlines in the U.S. District Court for the District of Columbia when no other federal law establishes a court with jurisdiction.

Section 1107. Programmatic environmental document.

Summary: This section would extend from five to ten years the period during which agencies may rely on programmatic environmental analysis without additional review of that analysis, subject to the existing exception for substantial new circumstances or information. After that period, agencies could still rely on the analysis if they reevaluate it

and determine that it remains valid. Programmatic reviews assess the environmental effects of a broader policy, program, or group of related actions and can provide a foundation for later project-specific reviews, reducing the need to repeat analysis that has already been completed.

Section 1108. Use of categorical exclusions by other agencies.
Summary: This section would create a centralized system for sharing categorical exclusions across the federal government, which agencies would have to update when a new categorical exclusion is created or adopted.

Section 1109. Applications for authorizations.
Summary: This section would establish deadlines for an agency to determine whether an application is complete or whether additional information is needed. The section would preserve shorter deadlines under other federal law for completeness determinations: Where another law provides a shorter completeness-determination period, the agency would begin the specified NEPA reviews and level-of-review determination on receipt of a notice of staking or similar prepermit submission notification. Once the application is complete, the agency would also face a separate deadline to determine whether the proposed agency action qualifies for a categorical exclusion, is not a major federal action, requires an environmental assessment, or requires preparation of an environmental impact statement.

Applicants for projects requiring NEPA review would also have to provide a list of known required federal, state, Tribal, and local authorizations; a record of pre-application stakeholder engagement meeting the requirements established earlier in the bill; and a brief description of the proposed agency action's purpose and need, project location, and known alternatives.

Manager's amendment: The amendment would clarify that shorter deadlines for determining application completeness established under other federal laws would continue to apply.

Section 1110. Judicial review.
Summary: Under this section, a NEPA claim would have to be filed within 150 days after the relevant authorization is published or otherwise made public. Where the agency provides a public-comment opportunity, occurring after enactment of this Act, the party bringing the challenge would have to have submitted a sufficiently detailed substantive comment raising the same issue. The plaintiff would also have to allege an actual or imminent injury amounting to direct harm.

Subject to applicable provisions of the Natural Gas Act and the Federal Powers Act, claims would go directly to the federal court of appeals for the circuit in which the project is to be constructed, expanded, or operated, rather than beginning in federal district court. The D.C. Circuit would have exclusive jurisdiction over claims challenging a rule's compliance with NEPA and claims involving projects with no physical location. The appeals court would also have supplemental jurisdiction over related claims challenging the validity of the same authorization. Cases would, to the maximum extent practicable,

be randomly assigned to judges and judgments would be issued as expeditiously as possible.

For a NEPA violation, remand without vacatur or an injunction would be the only remedy. This means the court would send the authorization back to the agency to correct the problem but would not vacate—or cancel—the authorization while the agency fixes it. The agency would have no more than 180 days to correct the deficiency, and both the authorization and the underlying project activity could remain in effect during that period.

Alternatively, and under limited circumstances, a court could issue a preliminary injunction, temporarily stopping an authorization while the lawsuit is still pending. To do so, the court would have to find a substantial likelihood that the authorization violates a federal law other than NEPA or the National Historic Preservation Act (NHPA); that an injunction is necessary to prevent irreparable harm; that the balance of equities favors the plaintiff, meaning the harm the plaintiff would face without an injunction outweighs the harm that temporarily stopping the authorization would cause to other parties; and that an injunction would be in the public interest. Any injunction could last only as long as reasonably necessary to correct the violation and prevent that harm.

When an agency prepares a supplemental or revised environmental document following a court order, a new 150-day challenge period would apply, but any subsequent lawsuit would be limited to new information contained in that supplemental document.

For actions authorizing use of lands, minerals, or other resources held in trust by the United States for a Tribe, NEPA-based administrative or judicial review would be barred. That restriction would not apply to challenges brought by the Tribe itself or challenges involving reasonably foreseeable effects outside the Tribal trust resources.

Courts reviewing NEPA claims would be required to give substantial deference to the agency regarding the scope and contents of the environmental document.

Finally, a final agency action could not be challenged under NEPA because the project sponsor omitted an engagement or other required information from the state, local, Tribal, and community portion of its record of stakeholder engagement.

The section would not create a cause of action or right to judicial review, limit claims alleging violations of an authorization's terms, or affect the established deadline-enforcement review provided under NEPA.

Context: Under existing law, NEPA challenges to federal agency actions ordinarily proceed under the Administrative Procedure Act and are subject to a six-year limitations period after a claim accrues. This extended window can leave projects exposed to litigation long after permits are issued, creating uncertainty for project financing and development. This section would substantially shorten that period while preserving judicial review for parties that meet standing and participation requirements. Shortening that window could benefit project sponsors by reducing their exposure to new legal challenges. However, it could also limit the time communities and other potential

challengers have to identify potential violations, develop legal claims, and seek judicial review.

Limiting courts to remand without vacatur as the remedy for NEPA violations would represent a significant shift from current law, under which courts may vacate an agency action, remand it without vacatur, or grant other appropriate relief depending on the circumstances. In its 8–0 decision in *Seven County Infrastructure Coalition v. Eagle County*, the Supreme Court recognized that deficiencies in environmental analysis do not necessarily require vacating a project approval. This provision would go further by requiring courts that find a NEPA violation to direct the agency to correct the deficiency within a specified deadline, without vacating the authorization or halting project activity. This could reduce the risk of construction or operations being interrupted while agencies correct procedural deficiencies, but would also limit courts' ability to halt projects when they find that environmental reviews were inadequate.

This section would not eliminate legal challenges under other federal laws, which may provide different remedies, including vacatur. It would also allow a court to issue a preliminary injunction where there is a substantial likelihood that the authorization violates a federal law other than NEPA or NHPA and the plaintiff also satisfies the requirements relating to preventing irreparable harm to the plaintiff, the balance of equities, and the public interest. This exception would provide a pathway for projects to be temporarily halted based on likely violations of other laws, but a deficient NEPA analysis alone would not be enough to halt a project.

At the same time, removing the possibility of vacatur or an injunction based solely on a NEPA violation could reduce the consequences of inadequate review and therefore weaken one of the incentives for agencies to complete a thorough analysis before allowing a project to proceed. Additionally, the bill would require agencies to correct deficiencies identified by a court within the court-ordered deadline, but it does not expressly specify what remedies would be available if an agency repeatedly failed to adequately address those deficiencies. The lack of explicit remedies for repeated noncompliance leaves some uncertainty about how courts would respond if an agency repeatedly failed to adequately address deficiencies identified on remand.

Manager's amendment: This change would clarify that the requirement for a plaintiff to have submitted a substantive public comment raising the issue being challenged would apply only when the opportunity for public comment occurs after enactment of this Act. It would also modify the provisions governing judicial venue by preserving applicable review procedures under the Natural Gas Act and Federal Power Act and specifying that the D.C. Circuit would have exclusive jurisdiction over NEPA claims challenging federal agency rules or authorizations for projects with no physical location.

Subtitle B—Council on Environmental Quality

Section 1121. Council on Environmental Quality.

Summary: This section would modernize federal environmental review and permitting systems by establishing government-wide data standards, digital tools, and a unified

permitting platform for federal agencies. This section refers to these digital tools collectively as eNEPA technologies.

Data standards

This section would require the Chairman, in consultation with other federal technology and permitting officials, including the Federal Permitting Improvement Steering Council (FPISC) Executive Director, to establish and regularly update common standards for how agencies collect and organize permitting and environmental-review data. The standards would cover information such as projects, environmental documents, public comments, geospatial information, public engagement, case events, and project milestones. Key agencies would then implement the standards. The goal is to allow information to be more easily shared and used across agencies and reduce duplicative work.

Minimum technology requirements

This section would require the Chairman to issue guidance establishing minimum digital capabilities for agencies involved in environmental reviews and permitting. These include tools for: automatically sharing application data among agencies; screening applications for completeness and potential categorical exclusions; managing projects and documents; conducting geographic-information-system analysis; compiling and analyzing public comments; and maintaining administrative records. The provision would also allow artificial intelligence (AI) to assist with analysis and comment management where appropriate.

Agency implementation

This section would require each key permitting agency to assess its existing technology against the new standards, develop an implementation plan to meet those standards, and begin implementing the standards and minimum requirements. Agencies would report progress to CEQ and the Office of Management and Budget at least twice each year.

Development of digital permitting tools

This section would direct the Chairman, in consultation with other agencies and the FPISC, to develop prototype tools to help agencies meet the new requirements, prioritizing tools for project management, application submission and tracking, public-comment tracking, automated processing, interagency data exchange, and accelerated complex environmental reviews.

ePermit unified interagency data system

This section would require the Chairman and key permitting agencies to develop an interconnected federal data system for environmental reviews and authorizations. A central component of that system would be a common, cloud-based authorization portal through which project sponsors could submit materials, track reviews and authorizations, and collaborate with agencies. The portal would draw information from agency systems rather than necessarily replacing those systems with a single database.

The portal would also provide information to communities and the public, including project status, public meetings, environmental-review notices, timelines, project locations, environmental documents, and mitigation measures, while protecting sensitive or classified information.

The system would track metrics such as changes in permitting timelines, use of the portal, public comments and community meetings, litigation related to authorization deficiencies, and agency compliance with the new technology standards. Congress would receive access to aggregated agency-performance data for oversight purposes.

Agency and personnel performance

This section would require the Chairman to develop outcome-based measures for assessing the performance of both permitting agencies and agency personnel involved in environmental reviews and authorizations. The measures would be used to identify high-performing practices that could be replicated, areas of poor performance that may need additional oversight or support, and opportunities to direct resources from the Permitting Improvement Fund toward improving agency performance.

Reporting and safeguards

This section would require CEQ to report annually to Congress on development of the ePermit system and agency performance. This section would also specify that the new technology framework does not authorize CEQ or another agency to impose regulatory requirements beyond those already authorized by law.

This section would also authorize $5 million annually to carry out NEPA.

Context: Federal permitting currently relies on multiple agency-specific systems that do not always communicate easily with one another. Common data standards and interoperable digital tools could create a more coherent process, making it easier for agencies to share information while giving project sponsors and the public a clearer view of where a project stands. More broadly, modernizing and digitizing permitting systems could reduce reliance on fragmented or paper-based systems and make deadlines, responsibilities, and outstanding decisions easier to track.

Importantly, the resulting greater transparency could also improve public participation by making it easier to understand when and how to engage, allowing the public to surface potential conflicts earlier in the review process. These changes are particularly notable given the changes to judicial review in section 1110, which would shorten the period for bringing legal challenges and place greater emphasis on participation during the administrative review process. Digital tools could help make those opportunities for engagement more accessible and transparent. These changes would not alter the underlying environmental standards agencies must apply, but they could make the process of meeting those requirements more efficient, accessible, and predictable.

Subtitle C—Federal Permitting Improvement

Section 1131. Definitions.

Summary: This section would define terms used throughout the Federal Permitting Improvement subtitle. The Executive Director would be the Executive Director of the Federal Permitting Improvement Steering Council (FPISC) established under FAST-41.

It would also create the term "transparency project" for projects that would include any project requiring an EIS and any project requiring an EA that remains incomplete 13 months after its applicable deadline.

Section 1132. Environmental Review and Permitting Tracker.

Summary: This section would require the FPISC Executive Director, in coordination with the CEQ Chairman and General Services Administration, to maintain an online Environmental Review and Permitting Tracker, as a component of the existing FAST-41 Permitting Dashboard, showing the status of environmental documents and federal authorizations for transparency projects.

Each project entry would include basic project information, the statement of purpose and need, project sponsor and lead-agency contacts, the status of any litigation related to the project, and quarterly updates on whether agencies are meeting the project schedule and statutory deadlines. If the schedule changes, the tracker would identify the reason for the change, including whether the delay was caused by an agency or the project sponsor.

For a transparency project already covered project under the FAST Act, its entry would also serve as its Tracker entry. The Executive Director would ensure that the entry contains the required information, and agencies or project sponsors would not be required to submit duplicate information for the two systems.

Manager's amendment: These changes would clarify that the environmental review and permitting tracker would be part of the existing FAST Act permitting dashboard. Where a transparency project is covered by the FAST Act, its permitting dashboard entry would serve as the entry for the transparency tracker. Measures should be taken so agencies or project sponsors would not have to submit duplicative information for tracking.

Section 1133. Permitting Improvement Fund.

Summary: This section would create a new Permitting Improvement Fund to improve the ability of key permitting agencies to complete environmental reviews and authorizations on time. The Chairman could transfer money from the Fund to agencies for activities including staff rotations between agencies, professional development, additional support for project managers, standardizing processes across regional and field offices, improving public engagement, or any other uses consistent with the Fund's purpose as determined by the Chairman.

The bill would authorize $20 million annually from fiscal years 2027 through 2033 for the Fund.

Section 1134. Limitation on claims for FAST-41 covered projects.

Summary: This section would shorten the FAST-41 deadline for challenging a federal authorization for a covered project from two years to 150 days after publication of notice in the Federal Register. A separate 150-day period would apply to claims based on new information in a supplemental EA or EIS, beginning with publication of the notice of the final agency action based on that document. Each shortened period would apply only when the relevant notice is published on or after enactment.

Manager's amendment: The manager's amendment adds this section to the bill.

Title II—Clean Water Act

Section 1201. Water quality criteria.

Summary: This section would require the Environmental Protection Agency (EPA) to use formal notice-and-comment rulemaking when developing water quality criteria under section 304(a) of the Clean Water Act (CWA), which directs EPA to develop nationally recommended, science-based criteria for determining what levels of pollutants or other conditions are protective of human health, aquatic life, and other designated uses of surface waters. States and authorized Tribes may use these recommendations when developing their own enforceable water quality standards.

This section would also make EPA water quality criteria under section 304(a) and EPA actions defining the scope of "waters of the United States" (WOTUS) directly reviewable through CWA's existing judicial-review framework. WOTUS is the term that determines the geographic scope of federal CWA jurisdiction.

Section 1202. Clean Water Act permitting and State certification.

Summary: This section would substantially revise section 401 of the CWA, which currently requires a certifying authority—a state, authorized Tribe, or EPA where no state or Tribe has authority—to certify that a federally licensed or permitted activity that may result in a discharge complies with applicable water quality requirements.

Scope of certification

This section would limit section 401 review to compliance with specified water quality requirements, including technology- and water-quality-based limits on pollutant discharges, state or Tribal water quality standards, standards for new sources, and requirements governing toxic pollutants and pretreatment. These requirements come from CWA sections 301–303 and 306–307.

A certifying authority could certify, deny, or conditionally certify a project. They could deny certification if it finds by clear and convincing evidence that no reasonable modification or condition could allow the project to comply with section 401 requirements or that required information remains missing after written notice and a reasonable opportunity to supply it. For a certifying authority to certify the project with conditions, the conditions would have to be necessary for water quality compliance and the least burdensome means of achieving compliance.

Application process

This section would establish a more detailed process for section 401 applications. Certifying authorities would be required to establish procedures for public notice, public hearings where appropriate, and optional prefiling meetings with applicants. The bill would also specify what information constitutes a complete application, including identification of the applicant and the federal license or permit subject to certification; the activity covered by that permit; the location and nature of any discharge and receiving waters; means to monitor, control, or manage the discharge; and other related federal, state, Tribal, interstate, or local authorizations.

Certifying authorities could promulgate regulations detailing additional requirements needed for application completeness. These additional requirements would have to be related to information needed to demonstrate compliance with water quality requirements and could reasonably be submitted at the time the application is submitted. Before December 31, 2027, an authority without effective regulations could identify additional requirements through one generally applicable written notice to applicants. On or after that date, an application that meets the statutory information requirements would be complete if the authority had not put additional requirements into effect through regulations.

Certifying authorities would also have to promptly acknowledge applications and either determine that an application is complete or identify any missing information in writing, including the water quality requirement for which the information is needed. Applicants could seek judicial review if a certifying authority fails to follow these procedural requirements, with injunctive relief available where appropriate.

Denials

If certification is denied, the certifying authority would be required to identify the specific water quality requirements that present an issue and explain the basis for the denial. Certifying authorities could deny an application due to insufficient information. In those instances, the certifying authority would be required to describe the data or information required to evaluate compliance with water quality requirements.

Timelines

This section would require the federal licensing or permitting agency to establish a reasonable period for a certifying authority to issue a final action on an application, not to exceed one year from receipt of the certification application. The provision would not require the application to be complete for the timeline for action to start. That timeline could be extended only at the applicant's written request and with the certifying authority's written agreement. If an applicant voluntarily withdraws their application and submits a new certification application, the reasonable period of time would restart. Failure of the certifying authority to act by the deadline would waive the certification requirement.

A certifying authority could also affirmatively waive certification, and such a waiver would not be subject to judicial review.

Judicial review

In court challenges to a denial, the certifying authority would bear the burden of demonstrating by clear and convincing evidence that no reasonable modifications or conditions would allow the certification to be issued without violating water quality requirements. In the case of a challenge to certification conditions, the certifying authority would be required to demonstrate by clear and convincing evidence that the conditions are necessary to meet water quality requirements and are the least burdensome options.

Interstate transmission and natural gas pipelines

This section would also establish a special rule for interstate electric transmission projects and interstate natural gas pipelines. For these projects, section 401 certification would apply only to a direct point-source discharge into WOTUS, rather than more broadly to the federally permitted activity. Certification or a waiver could satisfy the requirement.

The certification would still have to include any effluent limits, other discharge limitations, and monitoring requirements needed to ensure compliance with applicable water quality requirements, and those requirements would become enforceable conditions of the underlying federal license or permit. For facilities that are not subject to a separate federal operating license or permit, the certifying authority would also have an opportunity before operations begin to review how the facility will operate. If it determines that operation would violate applicable water quality requirements, the federal licensing or permitting agency could suspend the permit after a public hearing until compliance is assured.

If no applicable federal effluent limitation or performance standard exists for the direct point-source discharge, the certifying authority would certify that no such limitation or standard applies.

The review period for these certifications could not exceed nine months.

Context: Section 401 is an important part of the CWA's cooperative-federalism framework, giving states and authorized Tribes a direct role in determining whether discharges associated with federally licensed activities comply with water quality requirements. Because a federal license or permit cannot be issued without certification or waiver, section 401 can also have significant implications for whether and how a project moves forward.

Both narrowing the water quality requirements considered during certification and establishing more demanding standards for denials and conditions could make the process more predictable for project sponsors. These changes could also reduce the risk that section 401 is used to address concerns only indirectly related to the discharge or water quality. This could be particularly consequential for large infrastructure projects crossing multiple jurisdictions, as projects involving discharges in multiple states may

require separate certifications, increasing the opportunities for delays or denials. Interstate transmission lines and natural gas pipelines would receive additional streamlining because certification review would be expressly limited to direct point source discharges.

At the same time, these restrictions could limit the discretion of states and Tribes to respond to water quality concerns. In particular, the clear-and-convincing-evidence requirement and the least-burdensome-condition standard could make it more difficult to issue and sustain denials or protective conditions. Some observers have also raised concerns about the certification timeline because the review period would begin upon submission of an application without a prior determination that it contains all the information necessary to evaluate potential water quality impacts. This timeline could leave certifying authorities with insufficient time or information to conduct a thorough review, potentially resulting in certifications being waived or denied before outstanding water quality concerns are resolved. The express ground for denying certification when required information remains missing after notice and a reasonable opportunity to respond would give certifying authorities an additional way to address incomplete submissions, but it would not postpone the start of the review period.

Waivers would not be subject to judicial review, eliminating an avenue for outside parties to contest whether the certification requirement was properly waived.

Manager's amendment: The changes would clarify that certifying authorities may deny section 401 certification when an application remains incomplete after the applicant has received written notice identifying the missing information and a reasonable opportunity to provide it. It would also clarify that certifying authorities determine whether certification conditions are necessary to ensure compliance with water quality requirements and removes the requirement that those conditions be consistent with the underlying federal license or permit. The manager's amendment would establish a transition period through December 31, 2027, during which certifying authorities may impose additional application requirements through a single written notice applicable to all applicants, without first issuing regulations. After that date, authorities would need regulations to require information beyond the statutory application requirements. Finally, the amendment would expressly allow a waiver of section 401 certification to satisfy the certification requirement for qualifying interstate electric transmission projects and natural gas pipelines.

Section 1203. Permit term for NPDES permits.

Summary: This section would increase the maximum term for permits under the National Pollutant Discharge Elimination System (NPDES) from five years to ten years. NPDES permits regulate discharges of pollutants from point sources into waters covered by the CWA.

Section 1204. Permits for dredged or fill material.

Summary: This section would make several changes to CWA section 404, which governs permits for discharges of dredged or fill material, such as soil, rock, or sediment, into

WOTUS. The U.S. Army Corps of Engineers (Corps) generally administers the section 404 permitting program.

EPA authority

This section would limit the period during which EPA may use its authority under section 404(c) to prohibit, restrict, or withdraw the use of an area as a disposal site for dredged or fill material. EPA could exercise that authority only between submission of a complete section 404 permit application and issuance of the permit.

Section 404 general permits

General permits authorize categories of activities expected to have limited environmental effects, allowing qualifying projects to proceed without obtaining a separate individual permit. This section would extend the maximum term of section 404 general permits from five to ten years.

For general permits, this section would direct the Corps to consider only the effects of dredged or fill discharges on compliance with the same water quality requirements identified in section 401 and to treat discharges affecting less than two acres of navigable waters as having minimal adverse environmental effects.

Nationwide permits

Nationwide permits are a type of general permit that apply across the country to specified categories of activities, rather than only within a particular state or region. This section would require the Corps to maintain nationwide permits for activities currently covered by Nationwide Permits 12, 14, 27, 43, 57, and 58 when the discharge affects less than two acres of navigable waters per single and complete project. These permits cover categories of infrastructure including oil or natural gas pipelines, linear transportation projects (such a highways), aquatic ecosystem restoration, stormwater management facilities, electric utility lines and telecommunication activities, and utilities line activities for water and other substances. The Corps would retain authority to issue regional, state, and individual permits.

Reissuance of nationwide permits

This section would streamline reissuance of nationwide permits by providing that certain consultations under the Endangered Species Act and the NHPA would not be required. NEPA compliance could be satisfied through a programmatic EA, so long as the reissued permit does not make it easier for projects to proceed without additional preconstruction review by eliminating existing review requirements or increasing the thresholds that trigger them.

Context: EPA's authority under section 404(c) serves as a backstop to prevent the discharge of dredged or fill material into specific waters that would cause unacceptable adverse environmental effects. Although EPA has rarely exercised this authority, it has used it to restrict certain activities outside the ordinary permit-review window. Limiting the period in which EPA can exercise this authority could give applicants more certainty

by limiting EPA intervention to the period between a complete permit application and permit issuance. Some observers have expressed concern that limiting this authority to the permit-review window would reduce EPA's ability to intervene to prevent substantial environmental harm.

Extending the maximum duration of section 404 general permits from five to ten years could reduce how often the Corps has to revisit and reissue them, providing greater predictability for recurring activities. Because these permits authorize categories of activities expected to have limited environmental effects, reducing the frequency of renewal could also lower administrative costs for the Corps and permit users. At the same time, less frequent reissuance could mean fewer opportunities to reconsider permit conditions in light of new environmental information or changing conditions.

The changes to nationwide permits would streamline permitting for infrastructure projects by allowing more activities to qualify for these permits rather than undergoing individual permitting reviews. Most of the nationwide permits identified in this section have acreage limits of generally one-half acre of lost jurisdictional waters per single and complete project. This section would require the Corps to maintain these permits for qualifying activities involving discharges affecting less than two acres, potentially expanding their use. The existing acreage limits measure loss of jurisdictional waters, while this section refers to the area affected by discharges, so the change is not simply a numerical increase in the same threshold. This change could be particularly consequential for linear infrastructure, such as transmission lines and pipelines, which may cross numerous wetlands and waterways. Because separate water crossings can qualify as separate projects for nationwide permitting purposes, the two-acre threshold would not necessarily limit impacts along an entire route. However, acreage alone may not adequately capture environmental impacts, which can depend on factors such as habitat, hydrology, location, and cumulative effects. Requiring the Corps to treat discharges below two acres as having minimal adverse environmental effects could limit its ability to evaluate potentially significant impacts, particularly when multiple crossings collectively affect a larger area.

The changes to environmental review requirements for nationwide permit reissuances could also reduce administrative burdens and avoid repeated consultations when existing permits are renewed. However, these changes could limit opportunities to reassess environmental impacts under the ESA, NHPA, and NEPA, particularly as environmental conditions change over time. The exemptions would apply only to reissuances that preserve existing preconstruction notification requirements and thresholds, which could help maintain opportunities for project-level review. The provisions would not themselves eliminate otherwise applicable project-specific consultation requirements.

Manager's amendment: The changes would expand the list of covered general permits to include Nationwide Permit 27 on aquatic ecosystem restoration activities.

Section 1205. Judicial review timeline clarity.

Summary: This section would create new judicial-review rules for section 404 permits, general-permit verifications, and state section 404 permitting programs. Under the CWA,

a state may seek EPA approval to administer the section 404 permitting program instead of having those permits administered by the Corps.

This section would also establish a 150-day statute of limitations for challenges to EPA approval of a state section 404 permitting program, the issuance of an individual or general section 404 permit, and a Corps verification that a particular activity is authorized under an existing general permit. The period would run from issuance of the approval, permit, or verification.

For challenges to EPA approval of a state permitting program or to the issuance of an individual or general permit, a plaintiff would be required to have participated in the relevant public-comment process and raised the issue being challenged with sufficient specificity. This requirement would apply only where a draft action was published in the Federal Register and the agency provided at least a 30-day public-comment period occurring after enactment of this Act. It would not apply to challenges to Corps verifications that a particular activity qualifies under an existing general permit.

If a court finds that an individual or general permit was issued unlawfully, or that the agency acted arbitrarily and capriciously, the court would generally remand the matter to the Corps or state for further proceedings rather than invalidate or halt the permit. The court could vacate, revoke, enjoin, or otherwise restrict the permit only if it finds that the authorized activity would present an imminent and substantial danger to human health or the environment and that no other equitable remedy is available.

A similar standard would apply to challenges to Corps verifications under a general permit. If a court finds a verification unlawful, it could not enjoin or otherwise restrict the discharge unless the activity would present an imminent and substantial danger to human health or the environment and no other equitable remedy is available.

When a court remands a matter, it would be required to establish and enforce a reasonable schedule for the Corps, EPA, or state, as applicable, to respond to the court's order. That deadline would not exceed 180 days.

Context: The judicial-review changes in this section broadly reflect the approach taken elsewhere in this bill for NEPA, including a shorter statute of limitations, participation requirements for certain claims, and a shift toward remand without vacatur as the default remedy.

For section 404 permits, this shift in remedies could be especially consequential because these permits directly authorize activities that may alter wetlands and other waters. Allowing a permit to remain in effect during remand could provide greater certainty for projects that have already received authorization, while courts would retain authority to halt activity that presents an imminent and substantial danger to human health or the environment. At the same time, some observers may view that threshold as too high in cases where environmental harm could occur before a permitting deficiency is corrected, particularly where those effects may be difficult to reverse.

Title III—Endangered Species Act of 1973

Section 1301. Definitions.

Summary: To guide agency decisions, this section would create a statutory definition of "best scientific and commercial data available" and "best scientific data available," terms used throughout the Endangered Species Act (ESA). This section would define these terms to include relevant and objective scientific and commercial information available at the time of the agency action, including credible and reliable data, models, and analyses that account for known or potential error and are applied using prevailing professional standards. It would also specify that information must be gathered and applied impartially, without presumptions or policy prescriptions that bias its use.

Section 1302. Timeline for section 7 consultations.

Summary: Section 7 consultation is the process through which a federal agency consults with the U.S. Fish and Wildlife Service or National Marine Fisheries Service when an action it authorizes, funds, or carries out may affect a listed species, meaning a species formally designated as threatened or endangered under the ESA, or its designated critical habitat. The consultation evaluates whether the action is likely to jeopardize the species or adversely modify its critical habitat.

This section would shorten the timeline for completing consultation and the existing thresholds governing when longer consultations require notice to, or consent from, a permit or license applicant. It would also establish that if consultation extends beyond the statutory deadline without the required notice or applicant consent, the applicant could seek judicial relief for the agency's failure to act.

For projects that also require a NEPA environmental document, section 7 consultation generally would be required to be completed by the time the NEPA review is finished, unless extraordinary circumstances justify an extension.

Section 1303. Projects in the operational right-of-way.

Summary: This section exempts from ESA section 7 consultation projects that qualify for a NEPA categorical exclusion established in the Moving Ahead for Progress in the 21st Century Act. This exemption includes certain transportation projects in existing operational rights-of-way, such as resurfacing highways.

Section 1304. State assumption of consultation responsibilities.

Summary: This section would create a new voluntary program allowing participating states to assume certain responsibilities currently carried out by the Interior Secretary under ESA section 7 responsibilities for projects or agency actions located within their borders. If the affected area extends into another state, the participating state would have to consult either with that state, if it also participates in the program, or with the Interior Secretary. Projects or agency actions that cross state boundaries could not be assigned to a state under the program.

The Department of Interior would have to establish the program through rulemaking with a public-comment period. A state seeking to participate would have to demonstrate that it has sufficient legal, financial, and personnel resources, agree to waive sovereign

immunity for the responsibilities it assumes (i.e., states could be sued for those responsibilities), and provide a public comment period on its participation before applying. The Interior Department could deny an application only if the state fails to demonstrate the necessary legal, financial, or personnel capability, and could receive technical assistance to address those deficiencies, if requested.

A participating state and the Interior Department would enter into a written agreement specifying the responsibilities being transferred. States would have to maintain sufficient capacity, comply with the same consultation and NEPA deadlines that apply to the federal government, provide information needed for federal oversight, and accept federal-court jurisdiction over their performance of the assumed responsibilities. Agreements could last up to ten years and be renewed.

Once responsibilities are assumed, the state would carry them out in place of the Interior Secretary without further federal approval. However, a permit or license applicant could still elect for the relevant federal agency to consult with the Interior Secretary instead of the state.

The Interior Department would audit participating states annually during their first four years in the program and monitor compliance thereafter. Audits would be available for public comment. Audits could resume if there is reason to believe a state is not meeting its obligations. The Interior Department would be required to terminate a state's participation for inadequate performance after providing an opportunity to take corrective action, and a state could also withdraw voluntarily. The U.S. Fish and Wildlife Service would provide training and other capacity building initiatives to help states develop the capacity to participate in the program and to facilitate information sharing between states.

Context: Under current law, section 7 of the ESA directs federal agencies to consult with the U.S. Fish and Wildlife Service or NOAA Fisheries on the effects of federal actions on listed species and designated critical habitat, with states contributing information and expertise. Allowing participating states to assume Interior's consultation responsibilities could give states a larger role in reviews for projects located within their borders, similar to approaches that give states implementation responsibilities under other federal environmental laws, such as CWA and NHPA. For states with sufficient staff and wildlife expertise, this could allow consultation to draw more on localized species and habitat information. Whether this reduces delays would depend largely on state capacity. The separate funding authorization could support state capacity, but actual funding would depend on appropriations.

At the same time, participating states vary in their staffing, scientific expertise, resources, wildlife laws, and approaches to species conservation. Shifting consultation responsibilities from federal wildlife agencies to participating states could therefore lead to greater variation in how section 7 consultations are administered nationwide, leading some observers to express concerns that the change could weaken species and habitat protection in some states relative to the status quo. That concern may be particularly relevant for species whose ranges cross state boundaries or for migratory species. In both cases, actions in one state can affect a species that is managed and protected

across a much broader geographic area. The bill would require coordination with another participating state or the Interior Department in those circumstances, but would not require the Interior Department to approve each resulting consultation decisions.

This section's qualification requirements, federal oversight, mandatory termination, and interstate coordination requirements would likely address some of these risks.

Section 1305. Judicial review.

Summary: This section would generally require challenges to biological opinions—the written conclusions of section 7 consultations evaluating whether federal actions are likely to jeopardize listed species or adversely modify critical habitat—to be filed in the D.C. Circuit within 150 days after the biological opinion is made public. The exception is where the venue for judicial review is states in relevant NEPA or NHPA judicial review provisions.

Section 1306. Listing determinations.

Summary: This section would require the responsible federal agency to accept and integrate state-collected data when deciding whether to list or delist a species as threatened or endangered, provided the information meets this bill's definition of the best scientific and commercial data available from section 1301.

Section 1307. Authorization of appropriations.

Summary: This section would authorize $150 million annually from fiscal years 2027 through 2031 to support ESA section 7 consultation and state participation in the new state-assumption program.

Section 1308. National Fish and Wildlife Foundation Coastal State Fund.

Summary: This section would create a new grant program administered by the National Fish and Wildlife Foundation to support coastal state programs implementing natural and nature-based infrastructure, habitat restoration and protection, and related capacity-building and planning activities. Natural infrastructure would include features, such as wetlands, dunes, and reefs, that can provide flood protection, habitat, and other benefits. Funding would be allocated primarily equally among coastal states, with additional amounts based on tidal shoreline and coastal population density, and no state receiving more than five percent of total funding. Excess allocations would be redistributed among states that have not reached the 5-percent limit. The bill would authorize $50 million annually from fiscal years 2028 through 2032, subject to appropriations.

Section 1309. State wildlife action plans.

Summary: This section would require the Interior Secretary to conditionally authorize the implementation of a state wildlife conservation and restoration program when the state submits its comprehensive plan. The Secretary would set aside, from the state's apportionment, an amount not exceeding 75 percent of the estimated cost of developing and implementing the program. In consultation with the states, the Secretary would establish a review and approval process with a 180-day deadline after submission. If a plan remains unapproved after that period, the Secretary would report to the relevant congressional committees by June 1 of the calendar year following the year of

submission, explaining the delay. Final approval would remain subject to the retained statutory program requirements.

Manager's amendment: The manager's amendment adds this section to the bill.

Title IV—Project Certainty

Section 1401. Maintaining Federal authorizations or permits for projects with nonfederal sponsors.

Summary: This section would limit federal agencies' and federal departments' ability to revoke, suspend, reopen, materially modify, or otherwise interfere with federal authorizations or permits for projects or actions with nonfederal project sponsors that have secured all necessary federal authorizations or permits for construction or operation. This protection from interference would apply to a broad range of federal approvals in effect on or after November 6, 2026, including permits, rights-of-way, records of decision, findings of no significant impact, biological opinions, construction and operations plans, variances, departures, determinations, and other similar approvals or orders necessary for a project's construction or operation at full normal capacity. Federal agencies and departments would also be prohibited from taking other actions that interfere with construction or operation at normal capacity, subject to exceptions below.

Agencies or departments could still take such action in response to an order by a court; when the permit holder materially breaches the authorization or materially violates applicable law; when the authorization was obtained through fraud, intentional concealment, or material misrepresentation; at the request of the permit holder; pursuant to any applicable law or regulation; or when necessary to prevent immediate, specific, urgent, substantial, and proximate harm to life, property, human health, the environment, national security, or defense based on new information that was not considered in the underlying environmental review or final agency action.

In the latter case, the agency or department action would be required to be narrowly tailored in scope, duration, and degrees to what is necessary to remedy the identified harm.

Before interfering with an authorization or project, the agency or department would have to provide the permit holder with written notice explaining the action, the statutory authority supporting it, and the evidence on which it relies.

An affected permit holder could challenge an agency action in U.S. district court where the project is at least partially located or in the U.S. District Court for the District of Columbia, unless another law provides direct appellate review. The agency or department would bear the burden of demonstrating that one of the statutory exceptions applies. If the agency fails to meet that burden, the permit holder would be entitled to the reinstatement of the authorization and injunctive relief barring further agency interference with the project unless the agency first obtains an order from the same judge or another judge in the same district if the original judge no longer sits there. The permit holder would also be entitled to monetary relief paid from the Judgment Fund—a U.S. Treasury account used to pay court judgments and settlements against the federal government—for attorney fees, litigation and delay costs. Additionally, on a showing that one or more

federal agencies interfered with an authorization or permit in bad faith or interfered with the construction or operation of a fully permitted project in bad faith, the permit holder would be entitled to payments between 25 and 50 percent of the total development and construction costs incurred by the permit holder. The amount would be determined by the court, taking into consideration the degree to which the interference occurred due to bad faith, the degree to which there exists a pattern of similar interference in other projects, and the actual degree of economic harm. This section would preserve courts' existing equitable authority to grant available temporary or injunctive relief against an agency or department. On a motion for temporary or preliminary relief, a court could not consider the availability of cost recovery under this section when evaluating whether the permit holder's harm is irreparable.

A special rule would apply to projects that received a federal stop-work order within the two years prior to enactment that was subsequently enjoined or stayed by a court. Subsequent actions a federal department or agency takes or acquiesces to that interferes with the project would have no effect until the agency obtains an order from the judge who issued the injunction or stay, or another judge in the same district if necessary. That same judge would have jurisdiction over a challenge to subsequent federal interference with the project.

Payments to resolve covered disputes would require a final federal court judgment, including a court-approved settlement or consent accompanied by a court determination that it resolves a dispute within the court's jurisdiction, advances the section's objectives—including construction and operation of the project—and is fair, reasonable, and consistent with the public interest.

Manager's amendment: These changes would narrow section 1401's protections to projects or actions with nonfederal sponsors that have secured all necessary federal authorizations or permits for construction or operation, rather than also protecting individual permits for projects that have not secured all necessary approvals. It would expand the definition of federal authorizations or permits to include variances, departures, and determinations, and changes the applicability date from September 16, 2026, to November 6, 2026. The manager's amendment would add an exception for agency actions taken pursuant to applicable law or regulation, would expand the emergency exception to include harm to human health or the environment, and would require actions under that exception to be narrowly tailored. It would also remove the clear-and-convincing-evidence standard for agencies defending interference with an authorization or project, while retaining the burden of proof on the agency. The amendment would condition the additional monetary remedy of 25–50 percent of project development and construction costs on a showing of bad faith, would preserve courts' authority to grant temporary or injunctive relief, and would prohibit courts from considering the availability of specified monetary remedies when determining whether harm is irreparable. It would extend the lookback period for special protections involving previously enjoined or stayed federal stop-work orders from one year to two years. Finally, it would require payments resolving covered disputes, including settlements and

consent decrees, to be authorized by a final federal court judgment, with additional judicial findings required for settlements and consent decrees.

Context: Recent disputes over previously approved energy projects, including federal actions affecting offshore wind, have highlighted the risk that projects can secure permits, financing, and begin construction only to face later agency action that delays or reverses those approvals. Strengthening protections for issued federal authorizations could reduce that risk, improve investment certainty, and make it harder for administrations to target projects after permits have been issued.

The protections would apply across sectors and project types, for projects that have secured all necessary federal authorizations or permits for construction or operation, meaning future administrations would face similar constraints when seeking to revisit previously issued approvals for both clean energy and fossil fuel projects. This could provide greater stability for long-term infrastructure investment, although it would also limit the ability of future administrations to change course after an authorization has been granted. The manager's amendment would narrow the scope of these protections to fully permitted projects, rather than potentially protecting individual permits before a project has obtained all necessary approvals. This could address some concerns with how broadly this section could be applied.

The breadth of the protections also raises questions about how much flexibility agencies would retain after an approval is issued. The section would prevent not only formal interference with issued authorizations, but also actions that interfere with construction or operation at normal capacity of a fully permitted project. Some observers have expressed concern that this broad language could have unintended consequences—for example, inviting litigation claiming that subsequent regulatory actions (such as new health, safety, or environmental requirements) unlawfully interfere with an existing project. The manager's amendment would address some of these concerns by expressly allowing actions taken pursuant to applicable law or regulation, expanding the exception for urgent harm to include human health and the environment, and clarifying that the section would not limit agency authority under applicable law, compact, or treaty.

However, some observers remain concerned that the manager's amendment may not sufficiently preserve agencies' ability to exercise discretion under existing laws and regulations. Although the amendment would add an exception for actions taken pursuant to applicable law or regulation, it is unclear whether that language would adequately protect discretionary agency actions, rather than only those legally required.

The review standard and remedies would further reinforce those protections by shifting the burden to the federal agency to demonstrate that a statutory exception applies, and potentially exposing the government to substantial financial liability if the agency cannot justify its action under the section's standards. The manager's amendment would remove the heightened clear-and-convincing-evidence standard, which some observers were concerned was too high of a legal bar to meet, while retaining the burden of proof on the agency. It also conditions the additional monetary remedy of 25–50 percent of development and construction costs on a showing of bad faith. The risk of significant

financial penalties could deter unjustified federal interference, but it could also make agencies more cautious about revisiting existing approvals even where changed circumstances or new information may warrant action. These revisions could reduce concerns about financial liability for legitimate agency actions.

Section 1402. Ensuring fairness for specific types of covered projects.

Summary: This section would create a new cause of action for applicants that can demonstrate that federal permits or authorizations have been denied in bad faith or unreasonably delayed as part of an intentional pattern of disparate treatment by the federal government against a specific type of energy project. The provision would apply to a broad, technology-neutral list of covered energy project types, including wind, solar, storage, fossil generation and production, nuclear, transmission, pipelines, mining, hydropower, geothermal, hydrogen, carbon management, and other energy-related projects.

To establish a pattern of disparate treatment, an applicant would have to show a substantial increase in the percentage of denials or unreasonable delays for that same type of project (e.g., wind, solar, transmission) compared with the ten most recent calendar years of federal permitting data. The pattern would have to result from an intentional course of federal action undertaken to create the pattern. A substantial increase in denials would also require evidence of bad faith. Applicants could rely on permitting statistics and, as supporting evidence, agency policies, executive orders, official guidance, or statements by executive branch officials that demonstrate bias in the permitting process specifically.

The cause of action would apply only to denials or delays occurring after enactment of this bill, meaning the provision would not be retroactive to permitting decisions made before enactment. A qualifying pattern of disparate treatment would be required to persist for at least 280 days for permits that require an EA or EIS, or 180 days for permits that do not require an EA or EIS. At least that many days of the pattern would have to occur after enactment, and claims could not be filed until the corresponding 280- or 180-day post-enactment waiting period had elapsed.

For a delay claim, an authorization or permit would have to be more than 60 days beyond the applicable statutory deadline. The applicant would also have to show that its application complies with applicable federal law and that the authorization, if granted, would not be subject to cancellation for the specified legal violations, fraud, intentional concealment, or material misrepresentation.

Once an applicant has made a prima facie case, the federal government would bear the burden of either disproving the case or providing evidence of a lawful basis for the pattern. If an applicant successfully proves disparate treatment, a court would be entitled to injunctive relief, compensation from the Judgment Fund including attorney fees and litigation costs, economic damages associated with the denial or delay, and additional damages equal to 50 to 100 percent of the project's reasonably expected construction costs. In determining those additional damages, the court would consider factors including bad faith, a pattern of similar federal interference, and the economic harm to the

project sponsor. Applicants receiving relief would have to demonstrate the technical and financial ability to construct the project and any other projects for which they have applied for federal authorizations or permits and, after securing all necessary federal approvals and absent a showing of impossibility caused in substantial part by federal government interference, complete the project or repay all remedies received.

Payments to resolve covered permitting disputes would require a final federal court judgment. Court-approved settlements or consent decrees would require findings that they resolve a dispute within the court's jurisdiction, further the objectives of this section—including permitting, construction, and operation of the project—and are fair, reasonable, and consistent with the public interest.

Manager's amendment: These changes would extend the historical comparison period for identifying a pattern of disparate treatment from five to ten calendar years and would require denials to have occurred in bad faith, rather than simply being improper, to support a claim. It would also require evidence of bad faith when relying on a substantial increase in permit denials as prima facie evidence of disparate treatment. Once an applicant establishes a prima facie case, the federal government would bear the burden of disproving the case or providing evidence of a lawful basis for the pattern. The manager's amendment would also allow applicants to bring claims in the U.S. District Court for the District of Columbia. It would strengthen the requirements for receiving monetary remedies by requiring applicants to demonstrate the technical and financial ability to construct not only the project at issue but also other projects for which they have applied for federal authorizations or permits. It would replace the force majeure exception to the project-completion requirement with an exception for impossibility caused in substantial part by federal government interference. Finally, payments to resolve covered permitting disputes would require a final federal court judgment, including court-approved settlements or consent decrees accompanied by findings that they resolve a dispute within the court's jurisdiction, further the section's objectives, and are fair, reasonable, and consistent with the public interest.

Context: Federal permitting decisions can substantially affect whether energy projects move forward, raising concerns about the potential for administrations to favor or disadvantage particular technologies. This section seeks to deter administrations from systematically slowing or denying particular categories of energy projects for reasons unrelated to whether an individual project satisfies applicable law. This section would require applicants bringing claims to demonstrate both compliance with applicable federal law and an intentional pattern of disparate treatment affecting their project type. The manager's amendment would strengthen the requirements for challenging permit denials by expressly requiring bad faith, addressing concerns that legitimate permitting decisions could be challenged simply because they contributed to a statistical pattern of increased denials.

The ten-year comparison period (expanded from five under the manager's amendment) would establish a baseline for evaluating whether a particular project type has experienced significantly different permitting treatment. However, the choice of baseline

could influence which patterns are identified. Continued adverse treatment may therefore be difficult to challenge where the historical rate of denials or delays was already high, while substantially worse treatment of a previously favored project type could more readily support a claim, raising concerns that this baseline could put pressure on a later administration to maintain similar approval rates or timelines. Because the provision applies across covered project types, the same framework could protect clean energy projects from discriminatory treatment while also constraining similar treatment of fossil energy projects by a future administration.

The potential damages make this section particularly consequential. District court judges would determine whether the statutory requirements for unreasonable delay or bad-faith denial have been met, including disputed questions about how permitting deadlines are interpreted and applied. Some observers remain concerned that this section could invite litigation over these issues, particularly regarding when an application is considered complete and when the applicable deadline begins. Disagreements over these determinations could affect whether an agency is found to have unreasonably delayed a permit as part of a pattern of disparate treatment, potentially exposing the federal government to substantial financial liability. The availability of substantial monetary damages could strengthen incentives for agencies to avoid intentional disparate treatment, while also encouraging litigation over contested permitting decisions, deadlines, and the application of the ten-year baseline. The additional award would be based on expected construction costs rather than limited to the applicant's demonstrated loss, so it could exceed the economic harm caused by the denial or delay. Bad faith would be a prerequisite to a denial claim; unreasonable-delay claims would remain subject to the intentional-pattern requirement without the same express bad-faith prerequisite. The government's opportunity to establish a lawful basis for the pattern would help distinguish unlawful treatment from legitimate permitting differences. The requirement to demonstrate capacity to build all projects for which an applicant has sought federal approvals could also limit access to relief. The manager's amendment would further strengthen this requirement, and possibly limit relief, by extending it beyond the project at issue to other projects for which the applicant has sought federal permits.

These competing effects would depend in part on how courts interpret the provision's standards and assess whether agencies acted with the required intent. The manager's amendment would add safeguards against potentially unjustified claims, but questions remain about whether the potential financial liability could encourage litigation over legitimate agency permitting decisions.

Section 1403. Avoiding unreasonable delays in permitting.

Summary: This section would require decisions on federal authorizations or permits for covered projects that do not require an EA or EIS within one year after submission of the latest covered application. If applicable federal law provides for rehearing, the one-year period would instead begin the day after rehearing is completed or the day after the deadline to request rehearing expires. Applicants could seek judicial review in the district

where the project is at least partially located or in the U.S. District Court for the District of Columbia. Section 1503 would exempt specified nuclear authorizations from this deadline.

An agency would not be considered in violation of the deadline if it demonstrates by clear and convincing evidence that the delay resulted from specified circumstances, including a natural disaster or war, a national emergency, fraud or material misrepresentation in the application, the applicant withholding necessary information, or a lapse in appropriations lasting more than 14 days.

If the court finds that the agency failed to comply with the deadline, it would provide injunctive relief as appropriate and retain jurisdiction to ensure compliance. The court would be required to use expedited procedures and issue a decision within 120 days of filing, absent extraordinary circumstances. If relief is granted, the court would be required to order the agency to issue a decision on the application within 60 days.

Manager's amendment: These changes would move the one-year deadline for federal agencies to decide on authorizations or permits that do not require an EA or EIS from section 1402 to section 1403. It would also change the deadline's starting point from when the latest covered application is determined complete to when it is submitted and would add a special rule for authorizations subject to federal rehearing provisions, under which the one-year period would begin after rehearing is completed or the deadline to request rehearing expires. The manager's amendment would also allow applicants to seek judicial review in the U.S. District Court for the District of Columbia. A new provision in Section 1503 would exempt specified nuclear authorizations from the one-year deadline.

Context: Statutory permitting deadlines may offer limited predictability when applicants lack an effective means of enforcing them. By establishing a process for seeking judicial relief when certain authorization deadlines are missed, this section would make the one-year deadline enforceable in court. This change could provide greater certainty for projects that do not require an EA or EIS by reducing the risk that relatively straightforward federal authorizations remain pending indefinitely. The submission-based trigger would reduce reliance on the date of an agency completeness determination, but the application would still have to be complete. The rehearing rule could substantially postpone the start of the one-year period for authorizations governed by such procedures.

Some observers are concerned that this section does not define or limit the types of projects or actions subject to the one-year deadline, potentially extending the requirement to a broad range of federal authorizations that do not require an EA or EIS. Although this could accelerate permitting decisions across sectors, it could also strain agency capacity by requiring agencies to meet enforceable deadlines for a large number of applications, potentially diverting staff and resources from more complex or higher-priority reviews.

Title V—Nuclear Energy Licensing

Section 1501. Updating Hearing Procedures.

Summary: This section would allow the Nuclear Regulatory Commission (NRC) to issue construction permits, operating licenses, amendments, or combined licenses if no person whose interest may be affected requests a hearing. It would generally retain 30 days' notice and Federal Register publication, with the existing no-significant-hazards exception to those notice and publication requirements extended to amendments to combined licenses. Any hearings held under this section would use informal adjudicatory procedures. This section would apply to applications and proceedings pending before the NRC on or after the date of enactment of this Act.

Manager's amendment: The manager's amendment adds this section to the bill.

Section 1502.Licensing of uranium enrichment facilities.

Summary: This section would amend the Atomic Energy Act of 1954 to remove uranium-enrichment-facility-specific requirements for an EIS, a single adjudicatory hearing, and a pre-operation inspection. It would permit construction of a uranium-enrichment facility before issuance of its operating license under the same terms and conditions applicable to other fuel-cycle facilities. This would not modify the NRC's licensing authority, the applicability of NEPA to licensing decisions, hearing rights under the Atomic Energy Act, or the NRC's inspection authority. Applicants would have at least 15 days before construction of a uranium-enrichment facility to provide written notice be required to certify that they will provide written notice at least 15 days before construction to the state governor, the chief executive and governing body of each applicable local government, and applicable Tribes with offsite emergency response responsibilities.

Manager's amendment: The manager's amendment adds this section to the bill.

Section 1503. Applicability of deadlines to certain nuclear facilities.

Summary: This section would exempt specified certification, permits, approvals, licenses, amendments or other from the federal authorizations deadlines following the completion of an EA or EIS and from the deadline in section 1403. This would apply to nuclear production and utilization facilities, special nuclear materials, distribution of nuclear materials, and radioactive materials, and radioactive active waste disposal regulations.

Manager's amendment: The manager's amendment adds this section to the bill.

Section 1504. Compensation authority for career appointees.

Summary: This section would allow the NRC Chairman to set the annual basic pay for career appointees at a rate not greater than 110 percent of the maximum annual basic pay for senior executive service positions within the NRC. This section would not affect the certification of the performance appraisal system.

Manager's amendment: The manager's amendment adds this section to the bill.

Title VI—Other Environmental Matters

Section 1601. Wildfire emissions prevention.

Summary: This section would amend the Clean Air Act to treat prescribed fires, including Tribal cultural burning, as an exceptional event for air quality monitoring and regulatory purposes. An exceptional event is defined as an event affecting air quality, not reasonably controllable or preventable, and naturally or human-caused but unlikely to recur at that location. EPA would have to revise its regulations to reduce the burden and cost of demonstrating exceptional events, clarify prescribed-fire eligibility, and establish procedures for reviewing state petitions.

The section would also expand the regulatory determinations for which air quality–monitor data affected by an exceptional event may be excluded from consideration, including area designations, classifications, attainment determinations, and other Clean Air Act compliance determinations. For prescribed fires, it allows a causal relationship between the event and monitored air pollution to be reasonably expected rather than already established.

States could petition EPA to exclude exceptional event data for air quality–regulatory determinations. EPA would have one year to approve, disapprove, or partially approve and partially disapprove the petition. Petitions on which EPA does not act within that period would be deemed approved, unless EPA subsequently determines that the event does not qualify. At the request of multiple state or local agencies or Tribal authorities, EPA would be required to lead or collaborate on exceptional-event demonstrations affecting multiple jurisdictions.

This section would also clarify that stationary source emissions that did not qualify as exceptional events before enactment would not become eligible as a result of these amendments.

Subject to appropriations, EPA could award competitive grants to states, Tribes, and other eligible entities to address wildfire-smoke hazards in community buildings, including schools, and related activities. The federal share would generally be limited to 90 percent, with a possible waiver for facilities located in economically distressed communities, and no more than 25 percent of annual grant funds could go to recipients in one state.

Manager's amendment: The manager's amendment adds this section to the bill.

Context: Exceptional-event determinations affect how monitoring data are used for air quality regulatory compliance. Including prescribed fire as an exceptional event could reduce uncertainty for planned burning to help build local resilience to wildfires.

Section 1602. Brownfields revitalization.

Summary: This section would reauthorize and modify EPA's brownfields programs under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). It would add 501(c)(6) organizations to grant eligibility; establish a maximum of $500,000 per site for brownfield characterization and assessment grants; increase the maximum award for direct remediation to $1 million per site; increase the maximum for multipurpose

grants to $2 million; and allow grant and loan recipients to use up to 10 percent of their awards for EPA-approved demolition activities. It would also establish additional grant-ranking criteria for redevelopment of former military installations and reuse of brownfield sites for certain infrastructure-related activities and would require EPA to waive applicable matching requirements for eligible entities located in small communities or disadvantaged areas.

In each of fiscal years 2028 and 2029, EPA would provide one noncompetitive technical-assistance grant to help five selected applicants that unsuccessfully sought brownfield grants for small-community activities in the preceding fiscal year.

The section would authorize appropriations of $200 million annually for fiscal years 2027–31 for the federal brownfields program, with 0.5 percent available for oversight. It would authorize state and Tribal response-program assistance of $60 million in 2027, increasing by $5 million annually to $80 million in 2031. Recipients of state or Tribal response-program grants would maintain publicly accessible inventories, updated at least annually, of sites where grant-funded activities occurred. EPA's Inspector General would conduct biennial reviews or audits of the use of covering the specified federal, state, and Tribal funding.

EPA would issue and periodically update guidance on federal permitting and environmental review for brownfield projects, initially within one year. EPA would also be required to produce studies and reports on revolving-loan-fund, technical-assistance results, the feasibility of a larger loan program, and barriers to deleting or partially deleting cleaned-up sites from the National Priorities List.

Manager's amendment: The manager's amendment adds this section to the bill.

Division B—Committee on Energy and Natural Resources

Title I—Electric Transmission

Section 2101. Transmission permitting.

Summary: This section would substantially revise the federal backstop permitting framework for interstate transmission. Federal backstop authority allows the Federal Energy Regulatory Commission (FERC) to issue a federal construction permit for certain interstate transmission projects when a state lacks relevant siting authority, fails to act within the statutory timeframe, denies the project, or imposes conditions that make the project economically infeasible or undermine its transmission benefits. It would remove the current National Interest Electric Transmission Corridor (NIETC) designation process as a prerequisite to federal backstop permitting and instead allow qualifying transmission projects to access the federal process.

FERC would have to issue permits for projects in the national interest. Qualifying projects would be required to transmit electricity in interstate or foreign commerce; be consistent with the public interest; protect or benefit consumers, improve reliability, and facilitate just and reasonable rates; and operate at a voltage of at least 230 kV or be necessary to safely and reliably interconnect or operate one or more facilities meeting that threshold

for which the permit is provided. For facilities using advanced transmission conductors, including superconductors, FERC would establish alternative voltage thresholds based on comparable transmission capacity, with determinations made on a project-specific basis. For transmission upgrades, such as reconductoring, the projects would also be required to reasonably and economically maximize the capacity of existing towers, structures, and rights-of-way.

This section would preserve states' initial role in transmission siting but allows FERC-related prefiling to begin before a state application is submitted.

For projects that meet the eligibility criteria to be permitted under FERC's backstop authority, transmitting utilities that own, control, operate, or propose to construct the facilities and entities that would become transmitting utilities on completion of proposed facilities would be required to file tariffs allocating the costs of the new or modified transmission facilities. A FERC siting permit would not be required before filing these tariffs, provided FERC determines that the facilities meet the applicable eligibility criteria. FERC would be required to ensure those tariffs are just and reasonable and allocate costs to benefiting customers in accordance with the cost-causation principle, that is, they are roughly commensurate with the benefits, including through: improved reliability; reduced congestion; reduced power losses; greater carrying capacity that delivers improved reliability or reductions in the cost of delivered power; reduced operating reserve requirements; and improved access to generation that achieves reductions in the cost of delivered power. Customers that receive no benefit or trivial benefits would not be involuntarily allocated any of the costs of those transmission facilities. Utilities could recover all or part of the costs through voluntary agreements with its customers and allocate any remainder under these requirements.

For coordinated federal authorizations, FERC would act as the lead agency in the case of facilities permitted under this section and the Interior Department would act as the lead agency in the case of facilities located on a lease, easement, or right-of-way granted by the Interior Secretary under the Outer Continental Shelf Lands Act.

This section would allow recovery of prudently incurred costs associated with payments to jurisdictions impacted by transmission facilities developed through the federal permitting and transmission-planning frameworks.

This section would also direct judicial review of covered federal authorizations, including specified state approvals required under federal law, to the courts designated for review of FERC orders. The FERC siting authority framework would exclude ERCOT and would contain an exemption for specified state or their political subdivision, cooperative transmitting utilities receiving Rural Electrification Act financing or selling less than four million MWh annually, or their agencies, instrumentalities, and wholly owned corporations unless they voluntarily submit to FERC jurisdiction for the purpose of FERC siting authority.

Manager's amendment: This change would remove the explicit inclusion of transmission from the Outer Continental Shelf to a state from the types of transmission facilities eligible

for FERC permitting. It would also add facilitating just and reasonable rates to the criteria FERC must consider when issuing permits and expands eligibility to lower-voltage facilities necessary to safely and reliably interconnect or operate qualifying transmission facilities of at least 230 kV. For facilities using advanced transmission conductors, including superconductors, it would clarify that FERC may establish alternative voltage thresholds based on comparable transmission throughput on a project-specific basis. The manager's amendment would also remove the provision allowing developers of projects of at least 345 kV to submit federal permit applications to FERC while state permitting is underway, rather than waiting for a state decision or delay. Finally, it would clarify that developers may file transmission cost allocation tariffs with FERC before obtaining a federal siting permit, provided FERC determines that the facilities meet the applicable eligibility criteria.

Context: Under current law, FERC's backstop authority depends on DOE first designating a NIETC, meaning that even a transmission project that may otherwise warrant federal review cannot access FERC's permitting process unless it falls within a federally designated corridor. In practice, that framework has not produced an effective pathway for transmission development.

Replacing that corridor-based prerequisite with project-specific eligibility criteria could provide a more direct and predictable route for transmission projects that have demonstrated national value while preserving states' primary siting role. This change could be especially important for interregional transmission, where a single project may cross several states and can be delayed or prevented if one jurisdiction does not approve its portion of the line. A more accessible federal backstop could reduce that risk and increase the likelihood that projects with broad regional benefits are actually built. Greater interregional transmission could increase access to low-cost and clean power across planning regions, reduce congestion, provide savings for consumers, and improve reliability and resilience during extreme weather events.

However, some observers have raised concerns that expanding federal backstop authority could weaken state oversight of transmission development, particularly where states determine that a proposed project is unnecessary or its costs outweigh the benefits to their residents.

Section 2102. Reconductoring and other activities in existing rights-of-way.

Summary: This section would create a new statutory framework for activities that maintain or increase grid capacity within existing rights-of-way or the minimum adjacent area necessary to complete covered activities, provided the total additional area is not more than one quarter mile from the boundary of the right-of-way. Covered activities would be statutorily defined as not major federal actions under NEPA and not undertakings under section 106 of NHPA. Covered activities include the repair, maintenance, replacement, upgrade, modification, or expansion of existing transmission facilities, including reconductoring, voltage increases, circuit additions or adjustments, and installation of advanced transmission technologies (ATTs) and grid-enhancing technologies (GETs), as defined in section 2109 of this bill. They also include limited widening of existing rights-of-way, the addition of energy storage at or near existing

facilities, and the installation of parallel circuits within existing rights-of-way. ATTs and GETs are technologies that increase the capacity of existing transmission lines.

This section would establish similar treatment for specified activities on existing interstate natural gas pipelines within previously authorized corridors. Covered activities that remain within the existing right-of-way, the footprint of previously authorized and environmentally reviewed construction, and the minimum adjacent area needed to complete the work, provided the additional area is not more than one-quarter mile from the boundary of the right-of-way, would not be considered major federal actions under NEPA or undertakings under section 106 of NHPA. Covered activities would include repair, maintenance, replacement, upgrades, rebuilding, modification, optimization, minor relocation, looping, compression, capacity enhancement, and additions to existing pipeline facilities and associated infrastructure. The provision would not affect requirements under the CWA, CAA, or other federal laws not expressly addressed.

Manager's amendment: These changes would limit the additional area adjacent to existing electric transmission and natural gas pipeline rights-of-way within which covered activities would not be considered major federal actions under NEPA or undertakings under section 106 of NHPA to no more than one-quarter mile beyond the existing right-of-way boundary. It would also add the installation of GETs, as defined by section 2109, to the covered transmission activities.

Section 2103. Transmission planning.

Summary: This section would require the DOE, in consultation with affected states and Tribes, to conduct a study of electric transmission capacity constraints and congestion within one year of enactment of this bill and issue an update at least every three years thereafter. The report could identify areas experiencing, or areas expected to experience, transmission constraints or congestion that adversely affect consumers. The Energy Secretary would be required to consult with affected transmission planning regions at least once every three years.

This section would also establish a new framework for regional and interregional transmission planning. Transmission planning is the process utilities and grid operators use to identify where new or upgraded transmission will be needed, evaluate potential projects, and determine which projects should be selected to meet future reliability, affordability, and system needs. For purposes of these planning requirements, FERC would have jurisdiction over transmitting utilities, including certain entities that are otherwise outside ordinary FERC public-utility jurisdiction. The Electric Reliability Council of Texas (ERCOT) would be excluded from this planning jurisdiction.

States and their political subdivisions, electric cooperatives that receive financing under the Rural Electrification Act or sell fewer than four million MWh of electricity annually, and their specified affiliated entities would also be excluded unless they voluntarily subject themselves to FERC jurisdiction for these purposes.

Being subject to these requirements would not otherwise make those entities public utilities under the Federal Power Act.

FERC would be required to establish mandatory regional and interregional transmission planning processes. Each transmission planning region would be required to establish and submit to FERC for approval a regional transmission planning process and one or more joint interregional transmission planning processes with neighboring regions. FERC would be required to also establish rate treatments for regional and interregional transmission planning and cost allocation.

Those planning processes would be required to include common assumptions and models on consistent timelines that allow regions to identify and select specific regional and interregional transmission facilities; consideration of reconductoring, advanced transmission conductors, and other modifications that can maximize the capability of existing towers, structures, and rights-of-way; a common set of transmission benefits; and selection criteria requiring projects chosen for construction or modification to improve reliability, protect or benefit consumers, and be consistent with the public interest.

This section would use the same transmission-benefit categories and cost-allocation principles that apply to projects permitted under FERC's backstop authority. Transmitting utilities that own, control, operate, or propose to construct transmission facilities selected in regional or joint interregional transmission plans for cost allocation under qualifying planning processes would be required to file tariffs or tariff revisions with FERC allocating the costs of those facilities. Benefits would include improved reliability, reduced congestion and power losses, greater carrying capacity, reduced operating reserve requirements, and improved access to lower-cost generation. Costs would be required to be allocated to customers that benefit, consistent with the cost-causation principle and roughly commensurate with those benefits, while customers receiving no or only trivial benefits could not be involuntarily allocated project costs.

Transmission planning regions would be required to submit these planning processes within two years of enactment of this bill and conduct them, including the identification of transmission needs and the evaluation and selection of transmission facilities, at least every four years. The first planning cycle would be required to commence not later than one year after the date on which FERC approves the planning process. FERC would be required to review and approve the processes if they satisfy the statutory planning requirements, allocate costs in accordance with this section, ensure rates and terms are just and reasonable and not unduly discriminatory or preferential, and are consistent with the public interest. Compliance with previous FERC orders related to regional transmission planning would satisfy these regional planning and cost allocation requirements. FERC could grant an extension of up to six months if a region fails to submit a required planning process on time.

Projects selected through an approved regional or joint interregional transmission plan would also receive a streamlined path into FERC's backstop permitting process. For purposes of obtaining a federal construction permit, those projects would be deemed to satisfy the substantive project-eligibility requirements, including the interstate-commerce, public-interest, consumer-benefit, reliability, and voltage criteria, as well as

the requirement to maximize existing infrastructure where applicable. The project would still need to meet one of the state-related conditions that trigger FERC's backstop authority.

Approval of a regional or interregional planning process would not itself be considered a major federal action under NEPA. However, a FERC backstop permit for a project selected through a joint interregional transmission plan would be considered a major federal action.

Except as expressly provided in this section, nothing would be construed as conferring, limiting, or impairing any authority of FERC under any other provision of law.

Manager's amendment: These changes would expand the definition of exempt transmitting utilities beyond states, their political subdivisions, and electric cooperatives selling fewer than four million MWh annually to include cooperatives receiving financing under the Rural Electrification Act, regardless of electricity sales, and specified affiliated entities. It would also clarify that transmitting utilities proposing to construct facilities selected in regional or joint-interregional transmission plans for cost allocation, in addition to those that own, control, or operate such facilities, would be required to file cost allocation tariffs with FERC. The tariff-filing requirement would apply to facilities selected for cost allocation under qualifying transmission planning processes, rather than broadly to facilities constructed or modified as a result of this section. The manager's amendment would also require the first transmission planning cycle to begin within one year of FERC's approval of the applicable planning process and adds a savings provision clarifying that, except as expressly provided in this section, FERC's existing authority under other laws would not be conferred, limited, or impaired.

Context: Transmission planning is how utilities and regional planners determine what grid infrastructure will be needed in the future and which projects should be built to meet those needs. That planning is increasingly important as electricity demand grows, the generation mix changes, and more low-cost clean energy resources seek to connect to the grid. Because transmission projects can take many years to plan, permit, and construct, waiting until reliability problems or congestion are already severe can limit the options available to address those challenges and increasing costs. More forward-looking planning can help identify needs earlier, evaluate lower-cost solutions across a wider geographic area, and ensure that transmission investment supports reliability, affordability, and access to new generation.

FERC already requires regional transmission planning and interregional coordination through Orders No. 1000 and 1920. Order No. 1000 requires public-utility transmission providers to develop regional transmission plans and coordinate with neighboring regions to identify and evaluate potential interregional projects, but does not require them to develop a joint interregional transmission plan; Order No. 1920 requires long-term regional planning over a 20-year horizon. However, neither order requires neighboring regions to develop and submit a joint interregional transmission planning process comparable to the regional planning process. By establishing regional planning and cost-allocation requirements in statute, while recognizing compliance with existing FERC

orders, the bill could make those requirements less dependent on future changes in FERC policy. It would also establish new requirements for joint interregional planning, where progress has historically been more limited.

Transmission lines that provide benefits across multiple regions can be difficult to advance when each region develops plans primarily around its own needs, assumptions, and cost-allocation rules. Requiring compatible assumptions and models, common benefit categories, and joint project selection could make it easier to identify projects whose reliability and consumer benefits are only apparent when regions are evaluated together.

However, requiring more coordinated transmission planning would not necessarily resolve disagreements over which projects should be selected or how their costs should be shared. States, utilities, and other stakeholders may disagree about how to measure a project's benefits, particularly when the costs are concentrated in one region while the reliability or economic benefits extend across multiple regions. While this section would require costs to be allocated roughly in proportion to the benefits customers receive and protect customers receiving little or no benefit from being involuntarily assigned costs, determining those benefits could remain contentious. Cost allocation has already been a significant source of disagreement under FERC's existing transmission-planning rules, and disputes over how the bill's requirements are implemented could lead to further litigation, potentially delaying projects even after they have been selected through a planning process.

This section would also link planning more directly to permitting. A project selected through an approved regional or joint interregional planning process would be deemed to satisfy several of the substantive findings otherwise required for FERC backstop permitting. That would not itself authorize construction or eliminate the state-related conditions for federal backstop authority, but it would reduce the need to relitigate questions about a project’s reliability value, consumer benefits, and public-interest justification after those issues have already been considered through an approved planning process. This could create a smoother path from identifying a transmission need, to selecting a project, to ultimately permitting and building it.

Section 2104. Improvements relating to local transmission planning and development.

Summary: This section would enhance FERC oversight of local transmission planning, development, and replacement. FERC would be directed to establish procedures by which one or more state commissions could refer a public utility under their jurisdiction for an investigation into the processes used by the public utility for planning, developing, and replacing local transmission facilities. A local transmission facility would have to be located solely within the retail distribution service territory or footprint of a public-utility transmission provider and not be selected in a regional transmission plan for purposes of cost allocation. A referral would be required to identify the practices at issue, potential harm to wholesale or retail electric customers, and steps the state commission has already taken to address its concerns.

FERC could dismiss a referral as unsupported, provided it publicly explains the reasons for dismissal. Alternatively, FERC could issue a notice for initial public comment to begin an investigation and establish an investigative team that consists of staff from an office designated by the FERC Chairman and up to three representatives appointed by the referring state commission. The investigative team would have 120 days to issue preliminary findings and, if it identifies deficiencies in local transmission planning, development, or replacement processes, would issue a final report recommending remedies. FERC would then have 14 business days to provide notice of the final report for public comment and 120 days after that notice to issue an order.

If the investigation finds that a utility's local planning is not producing efficient or cost-effective facilities, or is interfering with regional transmission planning, FERC could require changes to planning processes, reduce the utility's return on equity for local facilities, eliminate the presumption that local investments are prudent, impose civil penalties of up to $5 million per facility (which would be credited to the transmission customers who bore the facility's costs), or issue any other appropriate remedy. The fine could apply only to a local facility developed or energized between 60 days before the referral and issuance of FERC's order, where FERC finds that development or energization was imprudent and caused financial harm to wholesale or retail electric customers in the referring state. FERC orders would be subject to rehearing and judicial review under the Federal Power Act.

Manager's amendment: These changes would clarify the definitions of "referring State" and "referring State commission," specifying that referrals must come from state commissions with jurisdiction over the public utility. It would expand the scope of investigations to include local transmission replacement processes and allows FERC to dismiss unsupported referrals with a public explanation. The manager's amendment would also permit investigative teams to include staff from an office designated by the FERC Chairman, establish deadlines for preliminary findings and FERC orders, and provide for public comment on the investigative team's final report and recommendations. It would replace fines payable to the referring state with civil penalties credited to transmission customers who bore the costs of the affected facilities and specifies the applicable procedures for rehearing and judicial review.

Section 2105. Prohibition of right of first refusal.

Summary: This section would prohibit a federal right of first refusal (ROFR) with respect to a transmission facility selected in a regional or interregional transmission plan for the purposes of cost allocation subject to exceptions under existing FERC rules or orders. An ROFR gives an incumbent transmission owner the first opportunity to build a project in its service territory before other developers can compete for it.

Manager's amendment: These changes would clarify that the prohibition on federal rights of first refusal for transmission facilities selected in regional or interregional transmission plans for cost allocation would be subject to exceptions under existing FERC rules or orders, rather than overriding those exceptions.

Context: Competition already exists for some regional transmission projects under FERC Order No. 1000, which requires the removal of federal ROFRs from certain regionally planned projects. Codifying this prohibition, while preserving exceptions under existing FERC rules and orders, and expressly extending it to qualifying interregional projects would provide more regulatory certainty, making opportunities for nonincumbent transmission developers less dependent on future FERC policy changes. This section would not eliminate state ROFR laws, which can still limit competition in some jurisdictions.

Allowing qualified nonincumbent developers to compete with incumbent transmission owners could help lower project costs, encourage innovative project designs and financing structures, and expand the pool of developers able to build needed transmission. However, some observers argue that competitive selection processes can introduce delays and additional costs, and that existing transmission owners are better positioned to develop projects because of their familiarity with the grid, relationships with state regulators and communities, and responsibility for maintaining reliability.

Section 2106. Consolidated planning process.

Summary: This section would direct FERC to issue a rule requiring each transmission organization to file a consolidated generation interconnection and regional transmission planning process. Interconnection is the process of connecting an electricity resource to the grid.

The planning process would be required to jointly evaluate electric transmission facilities and the generating capacity reasonably anticipated to be needed to meet both future demand and forecasted generation over the next 20 years. Transmission organizations would be required to routinely identify and publish resource- and fuel-neutral planned interconnection locations for generation and storage capacity and transmission capacity for customers, and an upfront, fixed, subregional per-megawatt fee for each planned generation and storage interconnection location, and it would establish a streamlined generator interconnection and transmission service request study process with a single decision point, meaningful and nonrefundable financial security, and withdrawal penalties sufficient to deter speculative projects, imposed after customers receive their total interconnection costs and any limitations arising from contingencies. The process would aim to co-optimize solutions to cost-effectively address electricity demand growth while integrating new generation and storage resources.

Planning processes would have to be submitted to FERC within two years of enactment of this Act and be conducted at least every two years. FERC would approve a process if it finds that it meets the requirements of FERC's implementing regulation and complies with the Federal Power Act's requirement that rates, terms, and conditions be just and reasonable and not unduly discriminatory or preferential.

Nothing in this section would prevent FERC from finding that the current generator interconnection and regional transmission planning processes are compliant with the requirements established in its implementing regulation, or that a transmission

organization achieves the objectives of this section through comparable processes that meet the objective of the implementing regulation during the FERC review.

Manager's amendment: These changes would narrow the consolidated planning process requirement from all transmission planning regions to transmission organizations, which include RTOs, ISOs, and other qualifying FERC-approved transmission organizations. Therefore, the requirement would not apply to every transmission planning region merely because it conducts regional planning.

This sections would expand the planning requirements to explicitly include storage interconnection locations and transmission capacity for customers, and changes the upfront interconnection charges from zonal costs to subregional fees. The manager's amendment would also revise FERC's approval criteria and allows FERC to recognize existing or comparable planning processes that satisfy the requirements of its implementing regulation.

Context: Generator interconnection studies assess the upgrades needed to connect proposed projects to the grid, while regional transmission planning evaluates broader infrastructure needs. Because these processes have historically been conducted separately, transmission upgrades needed to accommodate multiple generators may be identified later than necessary or planned on a project-by-project basis. Integrating interconnection and transmission planning through a proactive, 20-year process could allow shared transmission needs to be identified earlier, reduce interconnection delays, and avoid fragmented or redundant infrastructure, although the bill does not establish a specific deadline for completing interconnection studies.

Providing developers with upfront, fixed interconnection costs at planned connection locations could also help them assess where projects would be most economical to develop and help them make more informed investment decisions.

Some observers expressed concerns about how the consolidated planning process would operate in certain regions, particularly those without RTOs or ISOs. The manager's amendment would address these concerns by limiting the requirements to transmission organizations. However, this narrower scope raises questions about whether projects in different regions would have equitable access to streamlined interconnection processes and could limit the potential nationwide benefits of more coordinated generation and transmission planning.

Section 2107. Ratepayer protection.

Summary: This section would establish new ratepayer protections related to computational loads, including data centers, AI facilities, cloud computing, and cryptocurrency mining. This section creates two related but distinct sets of requirements.

First, FERC would be required to revise its transmission pricing policy and rules for computational load sites connected to the bulk-power system, including facilities used for AI, cloud and software services, cryptocurrency mining, and other data-center computational activities. Computation load sites would not include computing or data storage equipment that is ancillary to a commercial or industrial facility whose primary

purpose is not one of the specified computational activities. FERC would determine which customers are eligible for the new transmission pricing requirements through a rule or order.

Public utilities and transmitting utilities would be required to charge eligible computational load customers seeking transmission service on behalf of computational load owners and operators both the embedded cost and a reasonable assessment of the incremental cost of transmission service, with the goal of minimizing or avoiding cost shifts to other consumers (e.g., residential ratepayers). Embedded costs are the existing transmission costs already reflected in applicable rates, while incremental costs are the additional costs of expanding the transmission system to serve the new load. Incremental payments would be credited against utilities' transmission revenue requirements to prevent the same costs from being recovered from other customers. Computational loads that elect non-firm transmission service would be eligible for lower transmission costs. Non-firm transmission service allows customers to use available transmission capacity when it is not needed for higher-priority uses, but does not guarantee that capacity will always be available.

FERC would also require public utilities and transmitting utilities to conduct standardized analyses to a reasonably assess the incremental costs, as well as evaluate cost-reduction options. Utilities would be required to establish or revise transmission rates for eligible computational load customers and revise rates for existing customers consistent with the new pricing requirements. FERC could treat eligible computational load customers as a separate customer class and assign some or all transmission costs to that class rather than to individual customers. For transmission facilities selected through regional or interregional planning, or covered by consolidated planning process, incremental costs would be assigned in accordance with that process's statutory requirements or applicable FERC rules or orders.

Second, this section would establish broader ratepayer protections for computational-load sites, defined as one or more buildings, structures, or installations at a single location primarily used for activities such as AI, cloud computing, cryptocurrency mining, or other data center computational activities. Computing or data storage equipment ancillary to facilities primarily engaged in other commercial or industrial activities would be excluded. These protections would apply regardless of the site's electricity demand. For these computational-load owners and operators, this section would define retail incremental cost as a reasonable assessment of the costs that would have been avoided if the computational-load site were not served, including the costs of constructing, owning, and operating generation or storage resources and transmission and distribution infrastructure associated with serving that site. These costs would be estimated by the electric utility at or around the time the site becomes operational, subject to approval by FERC or a state, as appropriate.

No portion of those retail incremental costs could be allocated to or recovered from other customers. A covered computational-load owner or operator would remain responsible for unrecovered incremental costs even if it stops taking service before those costs are

fully recovered, and it would have to provide sufficient financial assurances or contributions before a utility constructs generation, transmission, or distribution facilities or upgrades needed to serve it. Financial assurances or contributions already provided to a public utility or transmission organization for the same site or upgrade would be credited against this requirement.

States could charge these computational-load owners and operators more than the retail embedded cost, meaning the average cost of electricity service reflected in the retail rates that would otherwise apply to them, and more than the retail incremental cost of serving them. States could also require revenues collected above retail incremental cost to be used to reduce rates for other retail customers. States could also use competitive solicitations or open seasons for computational-load owners and operators to contract for retail service, require a covered computational-load owners and operators to procure, construct, or contract for sufficient new generation to serve its demand, or condition service on a transmission-service arrangement that limits how much electricity the computational-load owners and operators can withdraw or the conditions under which it can do so. States would have broad discretion to conduct these solicitations themselves or authorize or require utilities to conduct them.

States could treat computational-load owners and operators as a separate customer class and establish rates, charges, terms, conditions, and interconnection or and service priorities that are less favorable than those provided to other large industrial, manufacturing, or commercial customers.

The ratepayer protection and state retail-service requirements in the second framework would apply to computation load sites interconnecting on or after enactment of this bill. Arrangements approved by FERC or a state before enactment would remain in effect although states could revise those arrangements to align with the ratepayer protection and retail-service requirements to the extent permitted under applicable state law.

Manager's amendment: These changes would expand the proposed rulemaking requirements to include standardized analyses of transmission upgrades, incremental costs, and cost-reduction options, as well as revised transmission rates for existing customers. The amendment would also allow FERC to treat eligible computational load customers as a separate customer class for cost allocation and coordinates incremental-cost assignments with the bill's regional, interregional, and consolidated transmission planning provisions.

The amendment would also expand the broader ratepayer protections for computational loads by eliminating the 20-MW threshold and applying the requirements to computational-load owners and operators regardless of their electricity demand. It would explicitly exclude ancillary computational loads. It revises the calculation of retail incremental costs to require a reasonable assessment based on utility estimates at or around the time a computational-load site becomes operational, subject to FERC or state approval, as appropriate. It would also clarify state authority to conduct competitive solicitations or require utilities to conduct them, recognizes existing state authority over retail electricity service rather than creating new authority, and allows states to revise

previously approved service arrangements to align with the new protections to the extent permitted under state law.

Context: Rapid growth in data-center electricity demand can require substantial investments in generation and transmission infrastructure, raising concerns that existing customers could bear costs associated with serving large new loads. The transmission-pricing provisions would create an exception to FERC's longstanding prohibition on "and pricing," under which a transmission customer generally cannot be charged both an embedded-cost rate and an incremental-cost rate for the same transmission service. For computational loads, this section would require both components to be charged, helping ensure that these loads pay both for use of the existing transmission system and for a reasonable assessment of incremental transmission expansion attributable to serving their demand.

These changes reflect a broader effort to limit the risk of costs from computational-load sites being passed to other electricity customers. Giving states flexibility to determine how to implement these protections could allow them to account for differences in utility regulation and local grid conditions. Determining reasonable increments costs could remain complex, especially where upgrades also provide broader system benefits.

Section 2108. Dispatchable energy systems market access.

Summary: This section would create federal rules governing participation of qualifying behind-the-meter distributed-energy systems (BTM DES) in wholesale electricity markets. A BTM DES is an energy storage system, fuel cell system, generator, or other resource located at a home, business, or other customer site on the customer's side of the utility meter. It connects to the grid through the customer's own electrical system, rather than through a separate direct grid connection.

To qualify to participate in the wholesale market, a BTM DES facility would have to be able to deliver electricity within 15 minutes of being called upon and have output that can be dispatched and adjusted at the system operator's signal, be located behind the meter of a retail customer of a distribution utility, provide between five kW and five MW of rated capacity, and maintain metering and telemetry capabilities. Multiple BTM DES facilities could be combined into a qualifying BTM DES aggregation so that, together, they are large enough (at least 100 kW of combined capacity) to participate in wholesale markets.

This section would prohibit transmission organizations from using rates, terms, or practices that prevent a qualifying BTM DES aggregation from participating in wholesale electricity markets. That would include energy markets, where resources are paid for the electricity they supply; capacity markets, where resources are paid for being available when needed; and ancillary-services markets, where resources are compensated for services that help keep the grid balanced and reliable. Prohibited practices would include imposing metering, telemetry, or equipment requirements that are more stringent than the definition of qualifying BTM DES facility and aggregation in this bill, requiring participation in the energy market with compensation as a condition of participating in the capacity market on equal terms, or requiring a BTM DES resource to participate jointly with another resource located at the same site. Nothing in this section would prohibit a transmission

organization from establishing performance rules for qualifying BTM DES aggregations that participate in capacity markets but not energy markets, subject to the condition that such rules are narrowly tailored to the purpose of ensuring the performance of such resources when called upon.

Transmission organizations administering FERC-jurisdictional wholesale markets would have to submit proposed rates, terms, and conditions implementing these requirements to FERC. FERC would have 180 days to approve the proposals or require changes to ensure compliance. FERC would also have to act on complaints alleging noncompliance within 180 days.

Participation in a retail market or program would not disqualify a qualifying BTM DES facility from participating in a wholesale market organized by a transmission organization. But payment from both a retail and wholesale market for the same service during the same time period would be prohibited. Transmission organizations would have to establish metering, settlement, and reporting procedures to prevent double compensation. These procedures would distinguish among energy, capacity, and ancillary services so that receiving retail compensation for one service would not necessarily prevent wholesale compensation for a different service. Distribution utilities would provide the necessary metering and retail program-participation information, subject to state protections for customer information, and aggregators would have to certify their facilities' retail program participation and compliance with the prohibition on double compensation.

Complaints alleging double compensation could be filed with FERC within five years. Where a facility or aggregation qualifies for both wholesale and retail programs, the complainant would have to demonstrate that double compensation occurred or is imminent and could not be avoided through reasonable adjustments to wholesale compensation or retail billing. FERC could initiate proceedings to adjust wholesale rates or terms to eliminate double compensation

FERC would have to order repayment of double compensation. Knowing retention could also result in monetary penalties of up to three times the double compensation received and suspension or termination of wholesale-market participation. Participating facilities and aggregations would also have to submit annual public reports to FERC summarizing and quantifying the services they provided to wholesale markets and state-jurisdictional retail programs during the preceding year.

This section would require any distribution utilities within an organized wholesale market to interconnect eligible behind-the-meter resource in a timely fashion. State authority over distribution-level interconnection and retail billing would remain. Interconnection terms would have to permit exports to the grid, where applicable, and not prevent, impede, or unreasonably condition wholesale-market participation. Distribution utilities and load-serving entities would also have to accept the metering and telemetry data used for wholesale-market participation, while states would determine how those data affect retail bills. The section would preserve utilities' ability to take actions reasonably necessary for distribution-system safety, reliability, and operations. Compliance with the

interconnection and metering requirements would be voluntary for certain publicly owned utilities and cooperatives unless required by state law.

Additionally, this section would establish a DOE program to help state, Tribal, and local governments adopt voluntary streamlined permitting and inspection processes for distributed solar, batteries, electric-vehicle charging, hydrogen refueling, and similar technologies through online permitting, standardized inspections, technical assistance, certification, and prizes. It would authorize $20 million annually for fiscal years 2026 through 2031.

Manager's amendment: These changes would establish a maximum capacity of five MW for individual qualifying BTM DES facilities and clarifies that transmission organizations would be allowed to establish narrowly tailored performance requirements for qualifying aggregations participating in capacity markets but not energy markets. The manager's amendment would remove the provision expressly preserving state authority over distribution-system and retail sales but would maintain state authority for a distribution utility to take action to maintain safety, reliability, or operations of the distribution system.

Context: BTM DES can provide flexible electricity supply on demand to stabilize the grid, lower energy costs, and provide backup power during outages. These resources can be aggregated into virtual power plants (VPPs) to reduce demand during extreme weather or high-load hours, in some cases helping prevent outages or defer the need for additional grid infrastructure. Some can also store electricity when prices are low and discharge it, or reduce electricity use, when prices are higher. Because BTM DES can be brought online far more quickly than other large-scale grid upgrades to meet surging local demand, enabling these resources to aggregate and participate in wholesale markets could create additional sources of flexible capacity and reliability services.

FERC Order No. 2222 already establishes a framework for aggregating distributed energy resources to participate in organized wholesale electricity markets. However, certain market rules and utility practices can still create barriers to participation. By establishing new statutory requirements for regional grid operators and distribution utilities, this section could expand opportunities for qualifying BTM DES to provide grid services and strengthen incentives for their deployment. The section's separate local-permitting provisions could further support deployment by reducing administrative barriers to installing distributed energy technologies.

Section 2109. Grid-enhancing advanced transmission technologies.

Summary: This section would direct FERC to require that public utilities evaluate opportunities to deploy grid-enhancing ATTs and use them when their benefits exceed their costs for covered projects. Covered projects would include constructing new transmission facilities and modifying, upgrading, replacing, or reconductoring existing facilities under FERC's jurisdiction. This section would define GETs as dynamic line rating, advanced power-flow control, transmission-topology optimization, and high-performance conductors.

FERC would require that public utilities evaluate their transmission systems to assess all technically achievable opportunities to deploy grid-enhancing ATTs, including the costs and benefits of such deployment. They would also be required to use grid-enhancing ATTs whenever the benefits of doing so would exceed the costs for covered projects. This would include using best-available class of transmission conductors, as determined by FERC based on commercially available capacity, electrical efficiency, mechanical performance, and economic reasonableness, taking into account reliability, safety, and affordability. In proceedings concerning recovery of ATT costs for covered projects, FERC would presume that using an ATT is prudent and that its associated costs are just and reasonable. FERC would also presume that the costs of using an ATT provide an economically reasonable alternative to technologies that are not grid-enhancing ATTs.

FERC would require that public utilities conduct recurring evaluations to determine whether the benefits associated with deploying grid-enhancing ATTs, including benefits to the current transmission system of the public utility, outweigh the costs. The evaluations would also assess whether the costs for which recovery is sought achieve the highest net benefit at the least cost for the applicable covered projects and consider planning and construction timelines and outages for new transmission assets and risks and impacts of potential delays.

If the benefits outweigh the costs, the applicable utility would be required to deploy the grid-enhancing ATTs on a timeline determined by FERC. FERC would also be required to establish penalties for failure to deploy qualifying technologies, potentially including reduced returns on equity. In the recurring evaluations, public utilities would be required to also evaluate planning and construction timelines for new transmission assets and the risks and impacts of potential delay and necessary outages, including whether technology deployment could reduce those impacts. Those evaluations would also include an assessment of the least-cost or highest net benefit and assess whether the costs reflect due care to minimize total project costs.

Manager's amendment: This change would revises the criteria for determining best-available transmission conductors to account for reliability, safety, affordability, and economic reasonableness. It would expand the presumption of prudence for cost recovery to include a finding that grid-enhancing advanced transmission technologies provide an economically reasonable alternative to other transmission technologies. The amendment would also revise the evaluation requirements to emphasize achieving the greatest net benefits at the lowest cost and would establish recurring evaluations of transmission planning and construction timelines, outages, and the risks and impacts of project delays.

Context: Grid-enhancing ATTs expand transmission capacity, improving power flows and reducing congestion; this leads to lower power costs for consumers. ATTs can be deployed more quickly and at a lower cost than new transmission lines, as they make use of existing infrastructure (e.g., pylons, towers, and substations), bringing reduced power costs to consumers sooner. Existing law already directs FERC to encourage adoption of ATTs, this section would require their deployment where benefits exceed costs. While

this could accelerate adoption of cost-effective technologies, some observers may argue that a federal deployment mandate could limit utilities' flexibility to account for differences in local geography, grid configurations, and operational needs, even with the bill's required cost-benefit analysis.

Section 2110. Expediting generator interconnection queues.

Summary: This section would direct FERC to initiate a rulemaking to revise the Large Generator Interconnection Procedures to require public utility transmission providers to share and use queue management practices involving computing technologies, including AI, machine learning, and automation, to expedite the evaluation and processing of interconnection requests. FERC would be required to initiate and finalize this rulemaking every four years to assess additional steps to ensure public utility transmission providers are adequately deploying computing technologies.

Context: Interconnection procedures govern how transmission providers evaluate requests to connect large generating projects to the grid and identify necessary system upgrades. Improved data sharing and greater use of automation, machine learning, and other computing technologies could accelerate these procedures and help reduce interconnection backlogs. Faster processing could help new resources come online sooner to meet rising electricity demand, support reliability, and expand access to lower-cost generation, including clean energy. However, the extent of these benefits would depend on implementation, and faster studies alone would not resolve other barriers to interconnection, such as the need to construct transmission upgrades.

Section 2111. Grid data access.

Summary: This section would establish requirements governing access to the grid data needed to conduct covered studies, including generation and load interconnection studies, feasibility studies, facilities studies, affected-system studies, and other studies required by the bill. Transmission providers would have to obtain, assemble, maintain, and use the grid data that is necessary to conduct these studies and could request necessary information from other bulk-power-system owners, users, and operators. Recipients generally would have to provide requested data within 15 days, unless FERC establishes another timeline for the data category. Data would have to be usable or convertible, accurate, complete, and current, subject to confidentiality and security safeguards.

FERC would have authority to order compliance and address complaints alleging violations. If FERC finds a violation, it would have to issue a compliance order, including interim relief to prevent unreasonable delay in a covered study. Failure to comply could be treated as a matter affecting reliable operation of the bulk-power system, and noncompliance by a public utility could be subject to penalties.

FERC and DOE would also develop a reference specification identifying the data categories, formats or conversion standards, update frequencies, and validation standards needed to enable greater automation of interconnection studies. The specification could not be updated more frequently than every three years.

Context: Automated and faster interconnection and transmission-planning studies depend on having complete, current, and machine-usable grid data. When inputs are missing, outdated, or incompatible, study teams may need to request additional information and reconcile data before completing their analysis. By establishing enforceable duties to provide accurate, current information in usable or convertible formats, this section could reduce such interruptions and support greater use of automated study tools.

Section 2112. Power marketing administrations.

Summary: This section would require the administrator of each of the federal power marketing administrations to develop, implement, and annually review a compensation plan for employees of the federal power marketing administrations, using compensation for comparable electric-industry positions in the locality and utilities in the relevant interconnection as benchmarks. Administrators would also receive greater flexibility to appoint and employ personnel, while retaining applicable merit-system principles.

The section would also preserve existing statutory protections for certain collectively bargained employees and exempt employees whose positions were covered by qualifying collective-bargaining agreements before March 27, 2025, from the new compensation and employment provisions. It would also restore federal collective-bargaining rights for power-marketing-administration employees as they applied on March 26, 2025, and preserve collective-bargaining agreements in effect on that date through their stated terms.

Manager's amendment: These changes would preserve certain existing collective-bargaining protections and restores collective bargaining rights and agreements that were in effect as of March 26, 2025.

Section 2113. FERC fee assessments.

Summary: This section would require FERC, at least once every five years, to review whether the fees and charges it assesses are sufficient to allow the Commission to handle its workload expeditiously and report the findings to Congress.

Section 2114. Collection of data on computational load entities.

Summary: This section would direct the administrator of the Energy Information Administration (EIA) to revise Form EIA-861, or its successor, to report separately on computational-load site, meaning one or more structures at a single location that primarily contain information-technology infrastructure used for creating, executing, and delivering software applications and services; AI training, deployment, and delivery; cryptocurrency mining; or other computational activities at a data center. Form EIA-861 collects operational, structural, and financial data from distribution utilities and power marketers of electricity.

Manager's amendment: These changes would alter the data-collection requirements from information on data center loads to computation-load sites.

Section 2115. De novo review of civil penalties under the Natural Gas Act.

Summary: This section would require FERC to follow the same procedures for assessing civil penalties under the Natural Gas Act as those established under the Federal Power Act. These procedures would allow entities facing civil penalties to elect de novo review in federal district court, where the court would independently evaluate the facts and legal issues underlying the penalty, as an alternative to an administrative hearing followed by judicial review.

Manager's amendment: The manager's amendment adds this section to the bill.

Section 2116. Transmission Organization governance.

Summary: This section would expressly give FERC jurisdiction over the corporate governance of transmission organizations, including RTOs and ISOs, for purposes of Federal Power Act sections 205 and 206, which govern FERC's authority to review proposed changes to wholesale electricity rates, terms, and conditions of service (section 205) and would require changes to those found to be unjust, unreasonable, or unduly discriminatory or preferential (section 206). This could allow FERC to exercise greater oversight of governance arrangements, including board structures, stakeholder representation, and decision-making processes.

Manager's amendment: The manager's amendment adds this section to the bill.

Section 2117. Data Center Community Assistance Program.

Summary: This section would require DOE to establish a Data Center Community Assistance Program to provide state, local, and Tribal governments with technical assistance on the potential impacts of data center development. Assistance could include providing information and analysis on electricity demand, generation and grid infrastructure needs, infrastructure costs and impacts on ratepayers, water consumption, cooling technologies, onsite generation, economic impacts, tax revenues, and other community information.

DOE would also be required to develop a publicly accessible toolkit for local officials explaining key technical concepts, questions to ask developers and utilities, and potential benefits and tradeoffs associated with data center development.

At the request of a state, local, or Tribal government, DOE could independently assess information voluntarily provided by developers, including the reliability of data and reasonableness of assumptions and projections. DOE would be required to identify material uncertainties and remain neutral regarding project approval. The section would not give DOE authority to approve, deny, delay, or otherwise participate in local data center siting decisions.

Manager's amendment: The manager's amendment adds this section to the bill.

Section 2118. Conforming amendments; savings provision.

Summary: This section would make conforming amendments to the Federal Power Act to incorporate the new provisions created by this title. It would also expressly provide that nothing in the title gives FERC authority over retail electricity sales or local distribution of electricity.

Title II—Energy Permitting

Subtitle A—Accelerating Claims

Section 2201. Accelerating claims.

Summary: This section would establish an expedited judicial-review process for federal authorizations for certain energy, mineral, carbon management, and wildfire-risk-reduction projects that also require a NEPA environmental document. Covered authorizations would include federal permits, lease sales, rights-of-way, and plans for energy and mineral projects under specified statutes; statements or permits under sections 7 and 10 of the ESA; and approvals for certain forest projects. Lawsuits challenging a final agency decision granting or denying a covered authorization would be required to be filed within 150 days after the decision is made public, unless a shorter federal period applies. The agency would have to make the decision public within three days of taking final action. Courts would be required to expedite their review and, if a decision is remanded to an agency, set a deadline of no more than 180 days for the agency to act, unless a longer period is necessary to comply with applicable law. If a supplemental or revised environmental document leads to a new authorization decision, that decision would receive its own 150-day statute of limitations.

Context: Lengthy periods of exposure to litigation create uncertainty for infrastructure projects even after federal authorizations have been issued. For covered projects, the changes in this section could reduce that risk and provide clearer timelines for resolving disputes. The 150-day statute of limitations would shorten the period during which project sponsors face the risk of new legal challenges, while the 180-day remand deadline could limit how long a project remains in regulatory limbo if a court identifies a legal deficiency. Together, these provisions could make financing, construction planning, and project development more predictable by reducing prolonged litigation and permitting uncertainty. However, the shorter filing window would also limit communities' and other potential challengers' time to identify legal violations and prepare claims. The remand deadline could also place pressure on agencies to resolve complex deficiencies within too limited a period.

Subtitle B—Federal Onshore Energy Leasing and Permitting

Section 2211. Permitting compliance on nonfederal land.

Summary: Under this section, federal drilling permits would no longer be required in certain cases where an oil and gas well is located on nonfederal land but involves federally owned oil and gas minerals. This exemption would apply when: the federal government owns less than 50 percent of the oil and gas minerals in the area associated with the well; a well on nonfederal surface and over nonfederal minerals enters and produces from federal minerals; or a well passes through federal minerals without producing from them.

Although a federal drilling permit would no longer be required in these circumstances, the Interior Secretary would still have to be notified of relevant state drilling applications and approvals involving federally owned oil and gas. The exemption would not apply to Indian lands, including lands held in trust or otherwise subject to federal restrictions on transfer.

The provision would not change the amount of royalties owed to the federal government for production from federal minerals, and the Interior Department would retain its other authorities under federal oil and gas royalty law. For wells covered by the exemption, the Interior Secretary's authority under the Mineral Leasing Act would be limited; the Interior Secretary could not require a bond to protect the nonfederal surface, enter the land without the landowner's consent, impose mitigation requirements, or require approval of surface reclamation.

Section 2212. Modification of Tribal lease and rights-of-way across Indian land.

Summary: This section would expand the existing authorization for Tribal leases under the Long-Term Leasing Act to include land held in trust for any federally recognized Tribe and would remove statutory lease-duration limits for leases issued under approved Tribal-leasing regulations.

This section would also create a new process allowing Indian Tribes to grant rights-of-way across their land without approval from the Interior Secretary, provided the rights-of-way are granted under Tribal regulations previously approved by the Interior Secretary. The Interior Secretary would be required to approve a Tribal regulation governing the granting of rights-of-way if it meets the statutory requirements. The regulations would be required to establish an environmental review process that identifies and evaluates significant environmental impacts, including a public comment period and responses to relevant and substantive public comments before approval of a right-of-way. The Interior Department's decision approving a Tribal regulation would not be subject to review under NEPA, section 106 of the NHPA, or the ESA.

For a federally funded project, an Indian Tribe could rely on the federal agency's environmental process rather than a Tribal review process.

The Interior Department would retain a backstop role. An interested party could ask the Interior Department to review whether the Indian Tribe followed its approved regulation after exhausting applicable Tribal remedies. If the Interior Department finds a violation, it would be required to give notice to the Indian Tribe and an opportunity to respond before the Interior Department takes corrective action, including rescinding approval of the Tribe's regulation and reassuming responsibility for right-of-way approvals.

Manager's amendment: These changes would expand the existing authorization for leases under the Long-Term Leasing Act to include land held in trust for any federally recognized Tribe. The amendment would also remove statutory limits on lease durations for leases issued under Tribal leasing regulations approved by the Interior Secretary.

Section 2213. Accelerating renewable energy permitting.

Summary: This section would expand the Energy Act of 2020's definition of an "eligible project," which currently covers projects that generate energy from wind, solar, or geothermal energy on federal land, to also include projects that store energy generated from those sources. This section would then apply new processing requirements to rights-of-way for those eligible projects.

For rights-of-way for eligible projects on federal land, this section would create new statutory deadlines for the Departments of Interior or Agriculture to determine whether an application is complete, issue a notice of intent when an environmental impact statement is required, and issue any required cost-recovery agreement. It would also require the agency, once an application is complete, to either grant or deny the right-of-way if applicable legal reviews are finished or identify the remaining applicant and agency steps and the timelines for completing them.

The Interior and Agriculture Secretaries would be directed to develop or adopt one or more categorical exclusions for specified "low-disturbance" renewable energy projects. Low-disturbance activities would include surface disturbances under five acres previously analyzed under NEPA; repeat activities at the same location that have occurred within five years; activities on previously disturbed or developed land for which a land use plan or analysis under NEPA, which was approved within the prior five years, identified the activity as reasonably foreseeable; the installation, modification, operation, or removal of solar photovoltaic systems located on structures or previously developed or disturbed land of less than ten acres; minor maintenance; preliminary geotechnical investigations; and the construction or removal of meteorological evaluation towers. Categorical exclusions would have to allow for extraordinary circumstances under which they would not be available.

Finally, it would direct the Bureau of Land Management's (BLM) National Renewable Energy Coordination Office to develop renewable-energy project review standards for use by regional renewable-energy coordination offices.

Context: Delays in federal right-of-way approvals can create uncertainty for clean energy and storage developers, particularly when application requirements or agency review timelines are unclear. The new right-of-way deadlines would give eligible renewable energy and storage project sponsors earlier information about application completeness, cost-recovery agreements, and outstanding requirements.

The categorical-exclusion requirements could eliminate the need to prepare an environmental assessment or environmental impact statement for qualifying low-disturbance activities. However, the agencies would first have to develop or adopt the exclusions, which would remain subject to extraordinary circumstance review. Extraordinary circumstances are conditions in which a proposed action that would normally qualify for a categorical exclusion may nevertheless have significant environmental effects and therefore require additional environmental review. Before applying a categorical exclusion, a federal agency must consider whether extraordinary circumstances are present that could result in significant environmental effects. Applying BLM's standardized review requirements could also promote greater consistency across regional offices and help reduce permitting timelines.

Section 2214. Electric grid projects.

Summary: This section would require the Interior and Agriculture Secretaries to each develop or adopt one or more categorical exclusions, subject to extraordinary circumstance review, for three categories of electric grid activity: placement of an

electric transmission or distribution facility in an approved right-of-way corridor; any repair, maintenance, or modification of an existing electric transmission or distribution facility or associated infrastructure on existing rights-of-way or previously disturbed land; and construction, operation, upgrade, or decommissioning of a battery or other energy storage technology on previously disturbed or developed land. Work on existing electric grid infrastructure would explicitly include reconductoring and grid enhancing technologies (GETs).

Context: Many of the fastest and most cost-effective ways to add transmission capacity involve getting more out of infrastructure that is already in place. Reconductoring can replace existing wires with higher-capacity conductors, and GETs can increase the amount of electricity that existing lines can safely carry or improve system power flows. Because these upgrades often use existing rights-of-way and previously disturbed land, they can normally be deployed more quickly than building new transmission corridors.

By directing the Departments of Interior and Agriculture to establish categorical exclusions for these activities, this section could reduce the time and procedural burden associated with federal environmental review where impacts are expected to be limited and well understood. Those exclusions could help accelerate lower-impact grid upgrades, increase capacity on the existing system, and provide near-term reliability and congestion benefits while larger greenfield transmission projects continue through development. The inclusion of storage on previously disturbed land would also be important for clean energy efficiency because storage can absorb excess wind and solar generation when it is available and discharge it later when output falls or demand rises, helping integrate more variable renewable electricity that might otherwise be curtailed or wasted.

Section 2215. Hardrock mining mill sites.

Summary: This section would revise federal mining claims to create a new category of "additional mill sites." It would also define these mill sites as public lands reasonably necessary for activities related to mineral development or production, such as waste-rock or tailings disposal. A mining operator could include, in an approved plan of operations, and use, as many mill-site claims as are reasonably necessary for the operation, although each individual mill site would be limited to five acres. Mill sites would not convey mineral rights and could not be patented into private ownership. Qualifying public land could include land that is mineral in character, nonmineral land, or land whose mineral character has not been determined, including tracts where the operator maintains an existing mining claim.

This section would preserve existing federal authority to regulate mining and would not reopen lands withdrawn from mining. Operators would pay a $400 annual maintenance fee for each additional mill site.

This section would also add "hardrock minerals" to the minerals that could be leased on federally acquired lands—meaning lands the federal government obtained after they were previously in state, local, or private ownership. It would define hardrock minerals to include minerals found in sedimentary or other rocks, base and precious metals, industrial

minerals, and precious and semi-precious gemstones and would exclude commodities already governed by other federal authorities, such as coal, oil, and gas.

This section would create an Abandoned Hardrock Mine Fund, which would receive revenue from the new mill-site maintenance fees and from hardrock-mineral leases on federally acquired lands. The Fund would be used to support abandoned hardrock-mine reclamation activities under the Infrastructure Investment and Jobs Act.

Context: Domestic hardrock mineral development depends on access to land for mining operations and associated infrastructure, including the facilities needed to manage waste rock and tailings. The Ninth Circuit's 2022 ruling on *Center for Biological Diversity v. U.S. Fish & Wildlife Service* (i.e., the *Rosemont* decision) clarified limitations on using public lands for these activities without a valid legal basis, such as a mining claim or mill site. By expressly allowing as many additional mill sites as are reasonably necessary under an approved plan of operations, the bill would reduce uncertainty over access to land needed for tailings, waste rock, processing facilities, and other infrastructure necessary to operate a mine. However, some observers have raised concerns that expanding access to mill sites could allow mining companies to use substantially larger areas of public land for waste disposal and other activities, potentially increasing impacts on water quality, ecosystems, and nearby communities.

Allowing hardrock minerals on federally acquired lands to be leased could also expand access to deposits that are not available through the traditional Mining Law claim system. This change could be relevant for minerals used in batteries, transmission, renewable energy, and other clean energy technologies, and more broadly for efforts to expand domestic mineral supply chains. Moreover, a wide range of hardrock minerals are necessary for economywide electrification—a key strategy to reduce harmful emissions. However, expanding access to mineral development could also raise concerns about environmental impacts and competing uses of federal lands, particularly where mineral deposits overlap with ecologically or culturally sensitive areas.

The Abandoned Hardrock Mine Fund could provide an additional source of funding to address legacy environmental and public-safety problems from historic mining, including acid-mine drainage, contamination from heavy metals, unstable waste piles and mine openings, and degraded land and water resources.

Subtitle C—Geothermal Leasing and Permitting

Section 2221. Geothermal observation test projects.

Summary: This section would create a new permitting framework for geothermal observation test projects, which are relatively limited exploratory wells used to test or monitor geothermal resources before full development. Qualifying test projects would be required to meet restrictions on size, road construction, and surface disturbance, generally including no more than 10 acres of disturbance per test project and no more than 100 acres for multiple projects. The test project generally would be required to be completed within one year, while site restoration would be required within three years unless the site moves into subsequent geothermal development.

This section would also require the Interior and Agriculture Secretaries to establish a NEPA categorical exclusion for qualifying geothermal observation test projects. Activities involving only "casual use"—activities that ordinarily cause no or negligible disturbance—would not be considered major federal actions under NEPA but would require advance notice. Administration of the categorical exclusion would remain subject to applicable extraordinary circumstance review.

Context: Geothermal developers need information about subsurface conditions before deciding whether to pursue commercial development. Confirming the presence and quality of a geothermal resource is an early and uncertain stage of project development, and these activities generally involve less disturbance than construction of a commercial geothermal facility. By creating a categorical exclusion for qualifying observation projects and excluding casual-use activities from major federal action status under NEPA, this section could make it faster and less costly to determine whether a geothermal resource is viable before a developer commits to a larger project and more extensive environmental review.

The definition of major federal action, as amended by Section 1102, would separately exclude agency actions associated with qualifying geothermal observation test projects from NEPA's definition of major federal action. How that exclusion would interact with this section's categorical-exclusion procedure, including its extraordinary-circumstances safeguard, remains unclear.

Section 2222. Geothermal royalties.

Summary: This section would amend the royalty schedule for geothermal electric generation. For the first royalty period, instead of measuring the first ten years of production under the lease, it would measure the first ten years from the facility's in-service date.

Section 2223. Geothermal leasing reform.

Summary: This changes the statutory minimum frequency of competitive geothermal lease sales from biennially to annually and requires the Interior Secretary to conduct a replacement sale in the same year if a scheduled sale is cancelled or delayed. It also establishes deadlines for considering and issuing geothermal drilling permits.

Section 2224. Geothermal Ombudsman and Permitting Task Force.

Summary: This section would create a new Geothermal Ombudsman position and would establish a Geothermal Permitting Task Force headed by this new role. The Geothermal Ombudsman would coordinate between BLM field, district, state, and national offices; provide dispute resolution services between BLM local and state offices and applicants for geothermal authorizations; monitor permitting practices and timelines; develop best practices for permitting and leasing for geothermal resources; and coordinate with the Federal Permitting Improvement Steering Council.

The Geothermal Permitting Task Force could temporarily assign qualified personnel among BLM offices to assist with geothermal authorizations. The Geothermal Ombudsman would report annually to Congress on the task force activities and the effectiveness of geothermal authorization processing during the preceding year.

Context: Geothermal projects can require multiple BLM approvals over several stages of development, and permitting delays can arise from limited agency capacity, inconsistent practices among field offices, or disputes between applicants and agency staff. These delays can increase project costs and make development timelines more difficult to predict, which in turn complicates financing and investment decisions. Improving coordination and providing a dedicated mechanism to resolve permitting issues could make federal geothermal permitting more coordinated, consistent, and predictable without changing the substantive standards projects must meet. Annual reporting could also make persistent problems more visible to Congress.

Section 2225. No Federal permit required for geothermal activities on certain land.

Summary: This section would eliminate the federal drilling permit requirement for geothermal exploration and production on non-federal surface land if any of the following conditions are met: the federal government owns less than 50 percent of the geothermal resources accessed by the proposed activity; the well is located on non-federal land overlying a non-federal mineral estate, but part of the wellbore enters and produces from a federal mineral estate; or the well is located on non-federal land overlying a non-federal mineral estate, but part of the wellbore traverses a federal mineral estate without producing from it. Operators must notify the Interior Secretary of state drilling permit applications and approvals affecting federally owned geothermal resources. This exemption would not apply to Indian lands. It would not affect federal royalties, and the Interior Department could conduct inspections to ensure accurate production accounting and royalty payments.

Manager's amendment: These changes would revise the circumstances in which geothermal exploration and production activities on nonfederal land would be exempt from federal drilling–permit requirements. The amendment would retain the exemption for activities involving less than 50 percent federal ownership of geothermal resources, would remove the requirement to submit a state permit as a condition of the exemption, and would add additional eligibility provisions for wells that produce from or traverse federal mineral estates. It would also make technical corrections to the notification provisions, replacing references to oil and gas with geothermal resources.

Section 2226. Effect of pending civil actions on processing applications relating to geothermal leasing.

Summary: This section would direct the Interior Department to continue processing authorizations for geothermal projects under valid existing geothermal leases, even when litigation affecting the application is pending. After all applicable federal legal requirements are completed, the Interior Secretary would be required to approve or deny the permit within 60 days unless a federal court vacates or provides injunctive relief.

Section 2227. Cost recovery from geothermal leasing, permitting, and inspections.

Summary: From this bill's enactment through September 30, 2033, the Interior Secretary could require applicants for, or holders of, geothermal leases to reimburse the United States for all reasonable costs associated with processing leases associated permit, plan, and other approval applications and inspecting and monitoring activities associated with the geothermal lease. The Interior Department could reduce reimbursement where full

payment would cause economic hardship or where a reduction would promote greater use of geothermal resources. The reimbursements should be spent, as appropriated, on geothermal permitting leasing and oversight activities. Within five years of enactment of the bill, the Interior Secretary would have to assess how the program affected the BLM geothermal program and any recommendations for updates and reauthorization of the program.

Section 2228. Publication of Gold Book for geothermal operations on Federal land.

Summary: Under this section, the Interior Secretary would have one year to identify standard procedures and guidelines for geothermal leasing and permitting that are not adequately addressed in BLM's fourth-edition *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development* (i.e., Gold Book). The Interior Secretary would have to publish an updated version of the Gold Book, incorporating procedures for ensuring the efficient review and approval of environmentally responsible geothermal development, and rename the book accordingly. The Interior Department would be required to review the guidelines at least every five years and update it when necessary. Each updated version would include exploration and geophysical operations, permitting lease operations, legal compliance, construction and maintenance, and drilling, production, and utilization.

Section 2229. NEPA review.

Summary: This section would exclude certain federal-land management actions related to the exploration or development of oil, gas, and geothermal resources from being considered major federal actions under NEPA. It would also extend several existing oil and gas activities that receive this treatment to geothermal development. For the activities receiving this treatment, the bill would expand the existing provision for pipelines placed in approved rights-of-way by allowing the corridor approval to be up to ten years old, rather than five. It would also add a geothermal-specific activity covering transmission or distribution lines of up to 20 miles in an approved right-of-way corridor that was approved within the previous ten years.

The section would preserve applicable drilling-permit requirements under the Mineral Leasing Act, Geothermal Steam Act, and Federal Land Policy and Management Act while providing that covered activities requiring such permits are not major federal actions under NEPA.

Context: Section 390 of the Energy Policy Act of 2005 establishes a rebuttable presumption that certain oil and gas activities on federal lands qualify for categorical exclusions under NEPA. Examples include drilling at sites used within the previous five years and placing pipelines in rights-of-way approved within the previous five years. Although categorical exclusions can streamline review, they remain part of NEPA's framework. Ordinary agency categorical exclusions generally require consideration of extraordinary circumstances that could make the exclusion unavailable. However, the treatment of statutory categorical exclusions established under section 390 has shifted over time, including changes in whether BLM requires extraordinary-circumstance review in implementing regulations.

Designating these activities as not constituting major federal actions would more definitively remove them from NEPA review, rather than relying on the categorical-exclusion framework. This could reduce uncertainty associated with changes in agency interpretations and implementation over time.

This section would also extend this streamlined treatment beyond oil and gas to geothermal activities, including certain drilling and development activities and short transmission or distribution lines serving geothermal projects. For oil and gas and geothermal developers, this could reduce permitting time and uncertainty for covered activities; however, excluding these activities from NEPA review does not necessarily establish that they have insignificant environmental effects.

Subtitle D—Hydropower

Section 2231. Identifying and removing market barriers to hydropower.

Summary: This section would direct FERC to submit a report to Congress on market barriers affecting the development and proper compensation of conventional, storage, conduit, and emerging hydropower technologies. The would be required to examine barriers related to transmission organization rules, FERC and Federal Power Act policies, and federal and state laws unique to hydropower development, operation, and regulation relative to other electricity sources. The report would be required to also include recommendations for reducing market barriers, identify potential regulatory, market, procurement, cost-recovery, ownership, and development models and solicit public input through a technical conference and comments on a draft report.

Section 2232. Certain conditions on issuance of licenses.

Summary: This section would require conditions imposed on FERC hydropower licenses for projects located within federal reservations to be reasonably related to the effects of the project.

Section 2233. Hydropower maintenance and temporary adjustments.

Summary: This section would require prior FERC approval for substantial alterations or additions to hydropower project work or operation that significantly depart from approved project plans. Routine maintenance, repair, or replacement necessary to maintain a project would not require approval or a license amendment. Prior approval also would not be required for qualifying temporary operational variances necessitated by circumstances beyond the licensee's reasonable control, including extreme weather, natural disasters, or equipment failures.

Section 2234. Micro hydrokinetic energy projects.

Summary: This section would create a new expeditated licensing process for micro hydrokinetic energy projects. A micro hydrokinetic project would be defined as a project that has an installed capacity of no more than 5 MW, generates electricity from waves, tides, currents, and does not impound water to generate electricity.

FERC could issue a license for 10 to 20 years for the construction, operation, and maintenance of these projects. FERC would have one year after the application is filed to take final action; FERC and other applicable conditioning or permitting agencies should

establish a joint schedule for all applicable federal decisions and authorizations that is consistent with the one-year deadline.

FERC would be required to create at least one categorical exclusion for low-disturbance activities associated with these projects.

FERC would also have to submit a report to Congress on the environmental, economic, and reliability and affordability effects of the projects licensed under this section.

Subtitle E—Hiring and Retention

Section 2241. Federal Energy Regulatory Commission staffing.

Summary: This section would expand the types of FERC employees eligible for special compensation intended to help the Commission recruit and retain hard-to-fill staff. Current law allows this authority for scientific, technological, engineering, and mathematical positions; the bill would add economic and legal positions. It would also remove the requirement that the FERC Chairman consult with the director of the Office of Personnel Management when using this compensation authority.

Section 2242. Federal Energy Regulatory Commission personnel safety.

Summary: This section would allow FERC employees to perform law enforcement duties for the safety of the FERC Chairman and Commissioners.

Manager's amendment: The manager's amendment deletes the previous section 2242, which would have updated the funding rules for the Pacific Northwest Electric Power and Conservation Planning Council, a regional body that develops power and conservation plans for the Pacific Northwest

Subtitle F—Offshore Energy

Section 2251. Offshore energy.

Summary: This section would change an offshore energy siting standard from "preventing interference with reasonable uses of the Outer Continental Shelf" to "preventing unreasonable interference with other uses." It would allow the Interior Secretary, in consultation with the Commerce Secretary, to grant rights-of-way within a national marine sanctuary for electricity transmission. Permits issued under the National Marine Sanctuaries Act for transmission cables on those rights-of-way would last for the same term as the underlying right-of-way.

Section 2252. Offshore energy transmission.

Summary: This section would establish a federal planning and permitting framework for offshore energy transmission. The Interior and Energy Secretaries would be required to identify preferred Outer Continental Shelf routes for transmission cables and sub-seabed infrastructure where routes have not been already identified, including routes between offshore generation facilities and routes connecting offshore generation to onshore electric grids. The secretaries would revisit these routes at least every three years to identify any additional necessary routes. When identifying routes, they would be required to consider existing rights-of-way and infrastructure, optimal points of interconnection between offshore generation facilities and onshore electric grids, and impacts on the marine environment and other ocean users.

The Interior Department would serve as the lead agency for coordinating all applicable federal authorizations and related environmental review for offshore transmission facilities. The Interior Secretary would also be required to issue regulations governing federal authorizations for offshore transmission facilities, including processes for identifying and assessing interest in rights-of-way, issuing rights-of-way on a competitive or noncompetitive basis, and addressing environmental review requirements.

Context: Offshore generation depends on transmission to deliver electricity to the onshore grid, and a project-by-project approach can lead to duplicative infrastructure and less coordinated interconnection decisions. Planning offshore transmission routes in advance and establishing a more coordinated federal approval process could help address these challenges by allowing transmission needs and potential conflicts with other ocean uses to be considered across multiple projects.

By identifying preferred routes in advance and creating a framework that can accommodate shared or "backbone" transmission connecting multiple offshore projects, this section could reduce permitting uncertainty, avoid unnecessary infrastructure, and support more coordinated offshore grid development. Coordinated planning could also help identify and address conflicts with other ocean uses earlier in the development process

Subtitle G—Department of Energy Nuclear Transparency Act

Section 2261. Public announcement requirements for Department of Energy actions relating to certain nuclear facilities.

Summary: This section would require DOE to publicly announce certain actions involving specified categories of nuclear facilities within 72 hours. These would include changes to directives or safety standards, the issuance of preliminary or final documented safety analyses, and agreements authorizing nuclear facilities. Announcements would be required to describe changes to safety standards, provide the relevant safety analyses, and identify any conditions associated with authorization agreements. DOE could redact commercially sensitive, classified, or other protected information from publicly released safety analyses. This section would apply to DOE nuclear facilities classified in Hazard Categories 1, 2, or 3, based on their radioactive material inventories and the potential consequences of an accident.

DOE would also be required to submit an annual report to Congress detailing activities undertaken to authorize covered nuclear facilities during the preceding calendar year.

Manager's amendment: The manager's amendment adds this section to the bill.

Title III—Historic Preservation

Section 2301. Historic preservation.

Summary: This section would substantially revise the scope of review, consultation procedures, and judicial review requirements under the National Historic Preservation Act, while also changing oversight of state and Tribal historic preservation programs. NHPA is a federal law that protects historic and culturally significant properties. Section 106 of the law requires federal agencies to consider how federal or federally connected

projects may affect historic properties before approving them. Agencies conduct these reviews in consultation with state historic preservation officers (SHPOs), Tribal historic preservation officers (THPOs), Indian Tribes, Native Hawaiian organizations, local governments, and other consulting parties.

State and Tribal Historic Preservation Programs

This section would strengthen federal oversight of state and Tribal historic preservation programs. State and Tribal programs would be evaluated by the Interior Secretary, in consultation with the Advisory Council on Historic Preservation, at least every two years, and repeated failure to meet statutory consultation timelines could result in a finding that a program is not complying with the law. The Secretary could disapprove programs for major inconsistencies and require suspension of specified contracts, cooperative agreements, and Historic Preservation Fund grants. For Tribal programs, before disapproval or suspension of contracts or cooperative agreements, the Secretary would be required to provide the Tribe and THPO with a written explanation of the deficiencies, offer technical assistance, allow at least 180 days to submit a corrective action plan designed to restore compliance within two years, and provide a reasonable opportunity to implement an accepted plan. If a major aspect of the program remains inconsistent two years after the initial determination following implementation of the corrective-action plan, the Secretary would be required to suspend specified contracts, cooperative agreements, and grants, in whole or in part. The Secretary would also establish a process for reinstating Tribal programs and restoring eligibility for suspended funding and agreements.

The Secretary could temporarily assume SHPO functions if deficiencies are not corrected, but would not be authorized to assume THPO functions or consult on behalf of a Tribe. Federal agencies would remain responsible for their Tribal consultation obligations. At a Tribe's request, the Secretary would also provide technical assistance, training, and capacity support in consultation with the THPO. The section would establish oversight and fiscal-audit requirements for Tribal programs, including periodic audits and the potential use of qualifying Tribal fiscal-management systems in place of comparable federal systems.

Scope of Section 106 Review

This section would define key terms that determine the scope of a section 106 review, including “undertaking,” “adverse effect of the undertaking,” “reasonably foreseeable,” and “area of potential effects.” An undertaking would have to require a federal permit, license, or approval and be subject to substantial federal control and responsibility. The definition would exclude, among other things, portions of a larger project over which a federal agency does not exercise substantial control or responsibility, as well as projects for which the federal government’s only involvement is most forms of financial assistance, except projects receiving more than $10 million in financial assistance from the Department of Transportation. Other exclusions would include specified minor or routine restoration, rehabilitation, repair, maintenance, and similar activities that do not diminish the integrity of a historic property, as well as qualifying public safety alterations,

nondiscretionary agency decisions, and certain special-use permit renewals and transfers. An adverse effect of the undertaking would have to be reasonably foreseeable and directly alter characteristics that contribute to a historic property's integrity. Consideration of visual, atmospheric, and audible effects would be limited to effects that directly and significantly affect the characteristics that make a historic property eligible for the National Register. Speculative or attenuated effects, as well as effects associated with unrelated projects, would also be excluded. The definition of adverse effect would also exclude temporary alterations limited to the time needed to complete an undertaking. The undertaking definition would exclude specified post-approval implementation and operation activities, while treating a subsequent discrete federal decision to amend or materially modify a determination as an undertaking to the specified extent.

Consultation Timelines and Coordination

This section would place enforceable deadlines on various stages of the consultation and reporting process for federal agencies, SHPOs, THPOs, and other consulting parties. Federal agencies would have 30 days after receiving request for review of a proposed project, activity, or program to determine whether it constitutes an undertaking. If an agency determines that an undertaking is a type of activity with no potential to cause any effect on a historic property, assuming one is present, it would have no further section 106 obligations. Agencies would follow applicable federal program alternatives when conducting reviews governed by those alternatives, subject to specified consultation, coordination, and other requirements.

For an undertaking, federal agencies would be required to solicit information from applicable SHPOs, THPOs, Indian Tribes, Native Hawaiian organizations, local governments, and applicants and seek, discuss as appropriate, and incorporate as applicable information provided within 30 days of the request. Within 60 days of determining that an activity constitutes an undertaking, the agency would have to complete a report and initiate consultation by submitting it to those parties, including when the agency determines that there are no adverse effects. The report would identify the area of potential effects, determine whether historic properties are present, document any adverse effects or determine that there are none, and identify prudent and feasible measures to avoid, minimize, or mitigate adverse effects. The report would consider only the portion of a historic property within the area of potential effects and explain any decision not to require mitigation because other considerations outweigh historic preservation.

When more than one federal agency has authority over a project, the agencies would designate a lead federal agency to manage section 106 compliance. If a lead agency has already been designated for purposes of NEPA, that agency generally would also serve as the lead agency for section 106, unless the agencies jointly determine that another agency is better suited. For projects subject to NEPA, section 106 consultation would begin no later than the start of the NEPA review and would have to conclude by the time the NEPA environmental document is completed. A draft NEPA document could also satisfy certain section 106 reporting requirements if it contains the required information

and the agency provides the required notice to consulting parties and the Advisory Council.

This section would specify findings through which an agency could satisfy its responsibilities without reaching an agreement with consulting parties, including that no historic properties are present, adverse effects would not diminish a property's integrity enough to make it ineligible for the National Register, or that other considerations outweigh historic preservation. The agency would have 90 days after submitting its report to make one of the specified determinations or reach an agreement with consulting parties, unless a shorter period is agreed upon by the specified parties. If an agreement is not reached, the bill would provide for an additional 60-day consultation period followed, if necessary, by formal comments from the Advisory Council on Historic Preservation, which would have 45 days to respond. The agency would then have 30 days to make a final determination explaining how those comments were considered.

Separately, agencies could proceed with their determinations if specified consulting parties do not respond within 30 days of a request to review a report or finding or raise substantive objections within 45 days of receiving a report or finding. If timely substantive objections are submitted, the agency would have 30 days to respond, explaining how it considered those objections. Providing that response would fulfill its consultation obligation concerning the report, without requiring agreement with the consulting parties. If a consulting party subsequently re-enters consultation after missing the 30-day response deadline, the agency would not be required to reconsider previous reports or findings and could consult with the Advisory Council instead of a SHPO or THPO. The agency could also enter into an agreement with the Advisory Council if a SHPO or THPO fails to respond to the agreement. Agencies would be required to notify applicable SHPOs, THPOs, Tribes, Native Hawaiian organizations, and local governments of final agency actions for undertakings requiring a report.

If a federal agency fails to complete consultation by the applicable deadline, specified senior federal officials would be required to devote at least 50 percent of their workweek to remedying the delay. Project applicants could seek expedited judicial review of federal agency compliance with consultation deadlines. Courts would be required to issue decisions within 120 days, absent extraordinary circumstances, and could order appropriate injunctive relief and establish a deadline of no more than 90 days for agency action.

Programmatic Alternatives

This section would require federal agencies, in consultation with the Advisory Council on Historic Preservation, to develop and implement program alternatives—including alternate procedures, programmatic agreements, exempted categories, standard treatments, and program comments—for categories of undertakings that normally have no adverse effects, are similar and repetitive in nature, or involve routine management activities at federal installations, facilities, or other land management units. Programmatic agreements are existing section 106 tools that establish standardized procedures for reviewing

categories of similar or recurring undertakings, reducing the need to conduct the full process separately for each individual activity.

SHPOs and THPOs could also develop and implement these types of program alternatives within their jurisdictions for categories of undertakings that normally have no adverse effects or are similar and repetitive in nature. Where federal and state or Tribal program alternatives govern the same type of undertaking, the state or Tribal alternative would apply unless the applicable SHPO or THPO agrees to use the federal alternative. The Interior Secretary would also collaborate with THPOs, Tribal leaders, and relevant nonprofit organizations to develop qualification standards for THPOs that reflect traditional knowledge, expertise, and access to traditional cultural leaders.

Judicial Review and Finality

This section would substantially revise judicial review of section 106 decisions. Claims would have to be filed within 150 days after the later of public availability of the final agency action and notification of the applicable SHPO or THPO, Tribe, Native Hawaiian organization, or local government, unless another federal law provides a shorter deadline.

Plaintiffs would have to show direct harm and, when a public comment period was available and occurred after enactment, would have to have submitted a substantive comment other than a form letter that sufficiently identified the issue being challenged. The direct-harm and public-comment requirements would not apply to claims involving sufficiently detailed written notice of the issue provided during consultation by a SHPO, THPO, Tribe, Native Hawaiian organization, or local government. Courts would be required to give substantial deference to the agency. If a court finds that an agency did not comply with the historic preservation requirements, the only remedy for that violation would be to send the decision back to the agency to correct the problem without vacating the agency action or stopping the project, with a deadline of no more than 180 days for the agency to act. A preliminary injunction could still be issued in more limited circumstances where there is a substantial likelihood of a violation of a federal law other than NHPA or NEPA, along with irreparable harm and the other traditional requirements for an injunction. Any such injunction could remain in place only as long as the court finds reasonably necessary to correct the violation and prevent the irreparable harm. Most section 106 challenges would also go directly to a federal court of appeals where the project would be constructed, expanded, or operated, subject to specified exceptions, including applicable judicial review provisions under the Natural Gas Act and Federal Power Act.

This section would provide additional finality once a section 106 review is underway. A property newly identified, nominated to, or listed on the National Register after an agency begins its review would not require the agency to delay, reopen, supplement, or otherwise modify the review.

Parties that did not sign a programmatic agreement would be prohibited from bringing lawsuits challenging how the agreement is implemented, and courts would not have jurisdiction to hear those challenges.

Cases would, to the maximum extent practicable, be randomly assigned to judges, and judgments would be issued as expeditiously as possible.

Manager's amendment: The changes would remove the proposed definition of properties of traditional religious or cultural importance and revises oversight of Tribal historic-preservation programs by establishing corrective action procedures before program disapproval or suspension of certain agreements. It would remove the Interior Department's authority to assume THPO functions, would establish a process for reinstating Tribal programs and restoring funding eligibility, and would clarify that DOI cannot consult on behalf of Tribes. It also removes the requirement that SHPOs and THPOs devote at least half their workweek to resolving overdue consultations.

The amendment would revise the definition of an undertaking to clarify exclusions for certain routine activities and federally assisted projects, with an exception for projects receiving more than $10 million in Department of Transportation assistance. It would expand consultation requirements by requiring agencies to solicit information from SHPOs, THPOs, Tribes, and other specified parties before completing their assessments and to initiate consultation through submission of a report, including when no adverse effects are identified. It would also extend the deadline for substantive objections from 30 to 45 days, would narrow when agencies may consult with the Advisory Council on Historic Preservation in place of other consulting parties, and would require notification of final agency actions.

The amendment would also expand the types of program alternatives that federal agencies, SHPOs, and THPOs may establish and would give applicable state or Tribal alternatives precedence over federal alternatives, unless the SHPO or THPO agrees otherwise. It also would clarify coordination with NEPA, would establish expedited judicial procedures for enforcing federal consultation deadlines, and would modify judicial-review requirements, including the timing of the 150-day filing deadline, public-comment requirements, and specified exceptions to direct appellate review.

Context: Section 106 of the NHPA is intended to ensure that federal agencies consider the effects of their decisions on historic and culturally significant properties before approving projects. However, consultation can be a lengthy and complex process, particularly for large infrastructure projects such as transmission lines and pipelines that cross multiple jurisdictions and may affect numerous historic or culturally significant sites. Although existing regulations establish response periods for certain consultation steps, there is no overarching statutory deadline for completing the process. This can make overall project timelines difficult to predict, particularly when disagreements over potential impacts remain unresolved.

The changes to the scope of review could make the process more predictable by focusing consideration on reasonably foreseeable effects directly connected to the federally authorized activity. This could be particularly consequential for transmission projects, where visual impacts may extend well beyond the project footprint and trigger extensive review of historic properties. Narrowing the consideration of visual, atmospheric, and audible effects could reduce the geographic scope and complexity of

reviews, while limiting review to portions of a project under substantial federal control could prevent a relatively narrow federal authorization from triggering review of an entire project. However, some observers have expressed concern that these changes would exclude impacts that are meaningful to affected communities, particularly where a property's cultural or religious significance depends on its surrounding landscape, viewshed, or traditional setting.

Establishing enforceable consultation deadlines and coordinating section 106 reviews with NEPA could reduce duplicative work and allow agencies to identify and resolve historic-preservation concerns earlier in project development. Requiring program alternatives for categories of similar or routine activities could further streamline reviews by establishing consistent procedures rather than repeating the full consultation process for each activity. However, tighter deadlines and stronger federal oversight could place additional pressure on state and Tribal historic preservation offices, many of which face staffing and resource constraints. The corrective-action and technical-assistance procedures would give Tribes an opportunity to address deficiencies before specified federal sanctions. Suspension of programs or funding could still affect Tribal consultation capacity, but the manager's amendment removes the provision that would have allowed for federal assumption of THPO functions or federal consultation on behalf of a Tribe, due to concerns around Tribal sovereignty. However, some observers remain concerned about these provisions infringing on Tribal sovereignty. Additionally, some observers may also be concerned that strict consultation deadlines could reduce the time available for Tribes and other consulting parties to identify and evaluate historic and culturally significant properties, particularly where disagreements over potential impacts remain unresolved. Allowing agencies to conclude consultation without reaching agreement with consulting parties could reduce their influence over decisions affecting historic and culturally significant properties.

The judicial review changes could provide greater predictability by shortening the period for bringing legal challenges and reducing the circumstances in which litigation could halt a project. Starting the filing period only after the specified notifications and applying the comment-participation requirement prospectively would qualify these limits. Shorter filing deadlines and limiting courts to correcting NHPA violations without vacating approvals or halting project activity on that basis could reduce financing risks and allow construction to continue while agencies address identified problems. However, limiting access to judicial review and remedies could also make it more difficult for affected communities and Tribes to challenge inadequate reviews or prevent damage to historic and culturally significant properties. Unlike some environmental impacts, the destruction of a historic or sacred site may be irreversible, meaning that correcting a procedural violation after construction has begun may not fully address the harm. Similarly, preventing newly identified historic properties from reopening an ongoing review could improve project certainty but limit opportunities to protect significant resources discovered later in the process.

Section 2302. Funding for the Historic Preservation Fund; use and availability; grants for Tribal Historic Preservation officers; additional funding.

Summary: This section would authorize $200 million annually for fiscal years 2027 through 2036 to the Historic Preservation Fund, which supports state, Tribal, and local historic preservation programs and related preservation grants. Expenditure of those amounts would remain subject to applicable appropriations requirements.

It would also authorize $20 million annually from fiscal years 2027 through 2030 for competitive grants to THPOs to develop online databases of Tribal historic preservation records and culturally significant properties that can support federal and state consultation. This section would not require public disclosure of specified sensitive property information where disclosure could cause significant harm or risk to the property's integrity or impede traditional religious or cultural use. It would also exempt information submitted to these databases and shared with federal agencies or SHPOs from disclosure under the Freedom of Information Act (FOIA).

Manager's amendment: These changes would retain the authorization of $200 million annually for the Historic Preservation Fund for fiscal years 2027 through 2036 but would remove the provision that would have made deposited funds available for expenditure without further appropriation or fiscal-year limitation. The amendment would also add a FOIA nondisclosure provision for information submitted to THPO databases developed under the competitive grant program, including information accessed by or shared with federal agencies and SHPOs.

Division C—Survivor Justice Tax Prevention Act

Sec. 3001. Exclusion from gross income of any damages, other than punitive damages, received on account of sexual acts or sexual contact.

This section would exempt certain financial damages received by survivors of sexual assault or other covered sexual contact from federal income taxation.

Manager's amendment: The manager's amendment adds this section to the bill.