

This document has been prepared as part of the implementation project of Legal Pathways to Deep Decarbonization (Michael B. Gerrard and John C. Dernbach, eds. Environmental Law Institute [2019]) (LPDD). For background information on the project, see <https://lpdd.org>

MODEL STATE LEGISLATION TO DECARBONIZE THE GENERATION OF ELECTRICITY¹

I. Introduction and Overview

A. Introduction

The goal of Chapter 23 of *Legal Pathways to Deep Decarbonization in the U.S.* is to identify those policy levers that will facilitate deep decarbonization of the U.S. electric power system.² With the prospects for comprehensive federal legislation uncertain, states across the country are increasingly exercising their extensive authority over electric utilities to decarbonize the electricity serving the citizens of their state. Although the choice of regulatory tools varies considerably, consensus is growing as to the necessary end-state: an electric power system that emits zero greenhouse gases (GHG) no later than mid-century.

Because the electric power system is interconnected across state lines, states should strive to enact legislation that is as consistent and complementary as practicable, thereby facilitating the most cost-effective path toward their shared goals. They should also attempt to learn from each other as they wrestle with a common set of challenging legal and policy issues, while recognizing that the facts, circumstances, and politics of each state are different.

To facilitate the sharing of emerging best practices, we have developed the model state electric decarbonization statute appended as Attachment A. Our template is based on 2019 legislation enacted in Washington State, the Clean Energy Transformation Act (CETA), which commits that state to a retail electricity supply entirely free of greenhouse gas emissions by 2045. Washington was chosen as an example of the 10 states (plus the District of Columbia and Puerto Rico) that have enacted statutes mandating the achievement of similar goals. Where appropriate, we reference provisions from those other statutes to highlight key principles and policy options.³

B. Overview of Model State Legislation

CETA commits Washington to a retail electricity supply entirely free of GHGs by January 1, 2045. In contrast to a cap-and-trade system or a carbon tax, both of which were

¹ This model law was drafted by Craig Gannett, Patrick Ferguson, Katie Jorrie and Anna Fero of Davis Wright Tremaine LLP, in consultation with LPDD chapter author Jim Rossi, Associate Dean for Research at Vanderbilt University Law School. Rick Horsch contributed editorial oversight.

² J. Rossi, *Electricity Charges, Mandates, and Subsidies*, in *LEGAL PATHWAYS TO DEEP DECARBONIZATION IN THE UNITED STATES* 598 (Michael B. Gerrard & John C. Dernbach, eds., 2019).

³ The early adopters in aiming for 100% clean energy by mid-century were Hawaii, California, and the District of Columbia. In 2019, Washington, New York, Maine, Nevada, New Mexico, and Puerto Rico joined them, and in 2020 Virginia enacted its legislation. Colorado and New Jersey enacted somewhat less ambitious legislation in 2019.

previously rejected by Washington State voters, CETA directly mandates utilities to achieve the 2045 end-state by meeting three increasingly stringent milestones.⁴ It facilitates compliance by assuring utilities that they will be allowed to recover prudently-incurred costs, providing alternative means of compliance during a transition period, and protecting customers against significant rate increases. The major features of CETA are:

Milestone I: No Coal by 2026

CETA's first step—eliminating coal-fired resources by 2026—is relatively simple in Washington State because most of the heavy lifting had already been done. Following years of intense negotiations arising from regulatory proceedings, two of the Northwest's three coal-fired power plants are scheduled for closure: Oregon's Boardman plant by 2020, and Washington's Centralia facility by 2025. That leaves only Montana's 1,480 MW Colstrip power plant.

Facilitating the withdrawal of Washington State's investor-owned utilities (IOUs) from Colstrip was an important objective of CETA. To do so, CETA directs the state's public utility commission (the Washington Utilities & Transportation Commission, referred to hereinafter as the Commission) to allow IOUs to recover all decommissioning and remediation costs prudently incurred as part of the withdrawal process. For other states intent on retiring their coal-fired generating plants, the recovery of stranded investment in those plants will be an important policy issue.⁵

Milestone II: GHG Neutrality by 2030

Achieving GHG neutrality by 2030 is far more complicated. CETA requires utilities to reduce or manage their retail load by pursuing all cost-effective, reliable, and feasible conservation and efficiency resources, and to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100% of the utility's average annual retail electric load.

Recognizing that moving to 100% renewables and non-emitting resources within a decade will be very challenging for at least some utilities, CETA allows them to satisfy 20% of that requirement through various alternative compliance options. The simplest of these options is to use renewable energy credits (RECs) or pay a cash penalty.

A more creative but less certain path would be to invest in what CETA refers to as "energy transformation projects." In addition to traditional home weatherization and energy efficiency measures, energy transformation projects include support for electrification of the transportation sector and investments in distributed energy resources. For example, CETA gives utilities credit for investing in infrastructure to connect more vehicles to the electric grid, and in the smart grid technology necessary to use the batteries in those vehicles as a form of energy

⁴ It is important to note that a cap-and-trade program, a carbon tax, and the mandatory/prescriptive approach used in CETA are not mutually exclusive. California, for example, combines a cap and trade program with a mandatory renewable portfolio standard. The Washington Legislature is expected to seriously consider adding a cap and trade system in 2021.

⁵ For discussion of some of the policy options related to stranded cost recovery for fossil-fuel plants, see Emily Hammond & Jim Rossi, *Stranded Costs and Grid Decarbonization*, 82 *Brooklyn L. Rev.* 645 (2017).

storage. This would allow utilities to charge car batteries at night when demand is low, and then draw upon those batteries during the day when demand is high, thereby reducing the need for additional generation to serve those high-load periods. Projects may also include support for hydrogen as a transportation fuel, investments in distributed energy resources such as small rooftop solar systems, investments in renewable natural gas systems, and projects to achieve emissions reductions in the agricultural sector.

Milestone III: 100% GHG-Free by 2045

By 2045, the final step must be complete: all electricity sold to Washington retail electric customers must be from generating resources that are either non-emitting or renewable. Recognizing the ambitious nature of both the 2030 GHG-neutrality and 2045 GHG-free mandates, the legislation includes two safety valves to protect customers.

First, there's a cost cap. Electric utilities are deemed to be in compliance with the 2030 and 2045 GHG standards if the average annual incremental cost of meeting the standards equals a 2% increase in the utility's weather-adjusted sales revenue above the previous year. Costs count toward the cap only if they are directly attributable to actions necessary to comply with the 2030 or 2045 GHG standards.

Second, reliability is given special consideration. Electric utilities are relieved of any penalty if it is found that compliance with the 2030 standard is likely to compromise the utility's ability to comply with NERC reliability standards, would violate prudent utility practice for assuring resource adequacy, or non-compliance is due to reasons beyond the reasonable control of the utility. Relief from a penalty is temporary, allowing sufficient time for the utility to comply with the standard. Also, the Commission and the Washington Commerce Department are required to report bi-annually to the Legislature on any impacts to system reliability. If they find adverse impacts, the Governor is authorized to delay the compliance deadlines until those problems can be addressed.

Vulnerable Populations and Highly-Impacted Communities. The Washington legislation stresses the importance of addressing the needs of communities that are highly impacted by fossil fuel pollution and climate change. Among other things, utilities must ensure that all customers are benefiting from the transition to clean energy.

Integration with Regional Energy Markets and Climate Change Programs. CETA mandates the creation of a stakeholder work group to facilitate the integration of regional energy markets and climate change-related programs. In particular, the work group is to examine the compatibility of CETA with an interstate cap-and-trade program.

II. Section-by-Section Summary and Key Policy Issues

The following summarizes each section of the model legislation and highlights the key policy issues raised. It also offers alternative approaches based on legislation enacted by the other states striving toward zero-carbon electricity.

Section 1. Findings and Purposes: This section contains the factual and policy basis for the legislation. Each state legislature should fashion these to align with its own factual circumstances, policy goals, and political considerations.

Section 2. Definitions: Like CETA, the model legislation requires, from 2030 through 2044, that utilities obtain electricity from either “non-emitting electric generation” or “renewable resources,” but with the ability to satisfy up to 20% of that requirement through alternative compliance options, including investment in “energy transformation projects.” These three definitions are therefore critical to determining compliance.

“Non-emitting electric generation” means “electricity from a generating facility or a resource that provides electric energy, capacity, or ancillary services to an electric utility and that does not emit greenhouse gases as a by-product of energy generation.” Conceptually, a separate definition of “renewable resources” is not necessary because, from a climate change perspective, whether a resource is renewable is irrelevant as long as it does not emit GHGs.

However, Washington – like more than 30 other states – already has a statute mandating that utilities use an increasing percentage of renewables over time (known as a renewable portfolio standard or “RPS”). CETA therefore allows compliance either through the use of “non-emitting electric generation” or “renewable resources.” It also allows the use of unbundled RECs as an alternative compliance option.⁶ **Policy issue:** In those states allowing unbundled RECs as an alternative means of compliance, it is critical that the definition of “renewable” be as consistent as possible. This is particularly true within regional power markets (*e.g.*, WECC or PJM), where RECs are frequently traded across state lines using non-governmental tracking systems.⁷ Ideally, nationwide REC fungibility would be achieved through a federal statutory definition of the environmental attributes of power generation that qualify for a REC (perhaps as part of a federal RPS requirement).

“Renewable resource” means: “(a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) renewable natural gas; (f) renewable hydrogen; (g) wave, ocean, or tidal power; (h) biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests; or (i) biomass energy.”

⁶ For a discussion of the legal basis for RECs, see <https://resource-solutions.org/wp-content/uploads/2015/07/The-Legal-Basis-for-RECs.pdf>.

⁷ States located in the WECC region (*e.g.*, Washington, California, Nevada, New Mexico) use the Western Renewable Energy Generation Information System (WREGIS) to certify, trade, and retire RECs based upon a standardized set of definitions. The 13 Northeastern states within the PJM region use a similar program called the Generation Attribution Tracking System (GATS) to standardize RECs and allow for their trading among PJM states. In the Virginia Clean Economy Act (2020), Virginia utilities were authorized to meet their RPS goals by purchasing RECs from renewable generators located anywhere in the PJM region. Va. Code Ann. § 56-585.5 (West 2020). Maine allows competitive electricity providers to satisfy certain requirements through the use of RECs. *See* Me. Rev. Stat. Ann. tit. 35-A § 3210(8) (2020). Maine utilizes the New England Power Pool Generation Information System (NEPOOL GIS) to issue and track RECs. *See* NEPOOL GIS, <https://www.nepoolgis.com/>. The District of Columbia restricts the geographical locations of renewable generators to the PJM Interconnection region but allows grandfathered resources to continue to produce RECs until January 2029. D.C. Code Ann. § 34-1431(10) (West 2019).

“**Energy transformation projects**” includes a broad range of investments, including in-home weatherization or other energy efficiency measures, electrification of the transportation sector, incentives for the purchase of electric vehicles, incentives for the installation of charging equipment, distributed energy resources, the development of new renewable resources to serve the sites of large industrial customers, and projects that achieve emission reductions in the agricultural sector.⁸

“**Vulnerable populations**” means communities that “experience a disproportionate cumulative risk from environmental burdens due to: (a) adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and (b) sensitivity factors, such as low birth weight and higher rates of hospitalization.”

Section 3. Milestone I: No Use of Coal-Fired Resources by End of 2025: Like CETA, the model legislation requires utilities to end their reliance on coal-fired generating resources by December 31, 2025. In return, utilities are allowed to recover in rates all of the costs they prudently incur in decommissioning and remediating those generating resources. A utility that fails to eliminate coal-fired resources from its resource portfolio by the end of 2025 must pay a penalty pursuant to section 9, below. **Policy issue:** As mentioned above, Washington will be able to end its reliance on coal-fired resources by the end of 2025 in part because two of the region’s three coal-fired power plants were already scheduled for closure. A 2025 deadline may be more challenging for states more dependent on coal-fired resources.⁹

Section 4. Milestone II: GHG Neutrality of All Retail Electric Sales by 2030: All retail sales of electricity must be GHG neutral by January 1, 2030, and carbon neutrality must be maintained from that date through December 31, 2044. Carbon neutrality is to be achieved and maintained through a two-step process. First, each utility is required to reduce its electric load by pursuing all cost-effective, reliable, and feasible conservation and efficiency resources. Second, each utility must show that its remaining load is served by electricity from renewable resources and non-emitting electric generation in an amount equal to 100% of the utility’s retail electric load.

⁸ For comparison, other tools used by states to promote resource diversification and encourage development of certain technologies include carve-outs and renewable energy credit multipliers for specific energy technologies, such as offshore wind, rooftop solar, or community energy. Carve-outs require that a certain percentage of an RPS standard be met with a specific technology or application, while credit multipliers award more RECs for electricity produced from certain technologies. See Brian Lips, *Credit Multipliers in Renewable Portfolio Standards*, North Carolina Clean Energy Technology Center (July 23, 2018), <https://www.cesa.org/resource-library/resource/credit-multipliers-in-renewable-portfolio-standards/>.

⁹ However, it’s worth noting that the Virginia Clean Economy Act, enacted in April 2020, requires nearly all coal-fired plants to close by the end of 2024, a year earlier than Washington. For comparison, California has virtually no in-state coal-fired generation, but obtains 4% of its electricity from out-of-state coal plants. It requires that the power purchase contracts with out-of-state plants be terminated by 2026, but assures full cost recovery. New York adopted new carbon dioxide emissions limits that will effectively close down all coal plants by the end of 2020. See N.Y. Comp. Codes R. & Regs. tit. 6, § 251.3 (2020) (the emission rate cannot be greater or equal to 1,800 pounds of CO₂ per MW hour gross electrical output or 180 pounds of CO₂ per million Btu of input). Hawaii’s sole coal-fired power plant is scheduled for retirement in 2022, Nevada’s sole coal-fired power plant is scheduled for retirement in 2025, and Puerto Rico has banned coal plants starting in 2028.

Alternative Compliance Options. Utilities that cannot meet this standard can satisfy up to 20% of their compliance obligation through one of four alternative compliance options: (1) pay a cash penalty; (2) use unbundled RECs; (3) invest in energy transformation projects; or (4) use electricity from a limited category of energy recovery facilities using municipal solid waste as the principal fuel. **Policy issue:** If the alternative compliance options are too plentiful and/or cheap, it will reduce the incentive to achieve GHG compliance. But if the options are too limited and/or expensive, utilities may not be able to comply at a reasonable cost. One approach would be to make the alternative compliance options relatively generous in the early years, and then increasingly constrained and/or expensive over time.¹⁰

Energy Transformation Projects. To obtain credit for investing in an energy transformation project, a utility must clear an array of hurdles. First, a conversion factor must be established to quantify the emission reductions from the energy transformation project in terms of megawatt-hours of electricity from non-emitting electric generation. For example, the GHG emissions avoided through a utility investment in electric vehicle charging stations must be converted to a certain number of megawatt-hours of electricity generated by a non-emitting resource. In addition, the emission reductions from an energy transformation project must be real, quantifiable, permanent, enforceable by the state, not required by another law, and not reasonably assumed to occur in the absence of the utility's investment. **Policy issue:** If the test to qualify as an energy transformation project is too stringent or time-consuming, utilities will be discouraged from pursuing them. For example, utilities have an important role to play in electrifying the transportation sector – a major source of emissions – but may hesitate to make the necessary investments if the prospects for obtaining credits are too uncertain.¹¹

Hydroelectric Generation. Under CETA, hydroelectricity counts as a renewable resource, but not if it results from new diversions, new impoundments, new bypass reaches, or expansion of existing reservoirs constructed after the effective date of the new legislation. However, utilities are free to make efficiency or other improvements to its existing hydroelectric generating facilities or to install hydroelectric generation in pipes, culverts, irrigation canals, and other manmade waterways, as long as those improvements comply with fish recovery plans and all local, state, and federal laws and regulations. **Policy issue:** Despite the fact that hydropower provides baseload, GHG-free electricity, CETA is not alone in limiting the types of hydroelectric

¹⁰ For instance, California allows IOUs to use unbundled RECs to comply with the state's RPS goals, but each year the percentage of their RPS requirements that can be met with unbundled RECs decreases (*e.g.*, from 25% of RPS requirements in 2013, to only 10% in 2020). See Cal. Pub. Util. Code § 399.16(c)(2) (West 2020).

¹¹ Aside from Washington's CETA, we are aware of no other state statute that allows investment in energy transformation projects to serve as an alternative means of compliance with a requirement to reach GHG reduction milestones. Other states incentivize energy transformation projects by other means. For example, the Virginia Clean Economy Act (2020) includes a broad definition of "electric distribution grid transformation project[s]" which provide utilities significant flexibility to invest in electric vehicle charging and related infrastructure. Va. Code Ann. § 56-576 (West 2020). However, the 2020 Virginia statute does not allow for investment in such projects to serve as an alternative means of compliance with a requirement to reach GHG reduction milestones. Instead, it allows investments in such projects to receive an enhanced return on equity. Va. Code Ann. § 56-585.1 (West 2020). Still other states, like Nevada, allow utilities to use energy efficiency measures to comply with a certain percentage of its RPS requirement. The percentage permitted decreases each year and may not count towards the standard after the year 2025. Nev. Rev. Stat. Ann. § 704.7821(2) (2019). Nevada utilities may also count towards the RPS standard electricity generated from a solar installation that the utility paid for or directly reimbursed a retail customer to acquire. Nev. Rev. Stat. Ann. § 704.7821(3) (2019).

development that qualify for treatment as a renewable.¹² Although these limitations are often justified in terms of the impacts of dams on fish, that concern can be met through the application of other laws specifically designed to address that important issue. Therefore, when enacting a climate change statute, legislators should avoid adding new barriers to the utilization of climate-friendly resources.

Nuclear. Like CETA, the model legislation does not explicitly address the role of nuclear power, but it squarely fits within the definition of “non-emitting electric generation” because it “provides electric energy, capacity, or ancillary services to an electric utility and that does not emit greenhouse gases as a by-product of energy generation.” ***Policy issue:*** Incentivizing the development and/or continued operation of nuclear power is controversial in many states, but as a factual matter it helps address the climate change crisis by producing baseload, GHG-free electricity.

Vulnerable Populations and Highly-Impacted Communities. Like CETA, the model legislation requires the relevant state agency to designate communities that are highly impacted by fossil fuel pollution and climate change. In turn, utilities, in preparing their integrated resource plans (IRP), must ensure that all customers are benefiting from the transition to clean energy. Specifically, they must pursue equitable distribution of the energy and non-energy benefits of clean energy, and reduce the burdens to vulnerable populations and highly-impacted communities. In doing so, they must consider the long-term and short-term public health and environmental benefits in terms of reducing risk and increasing energy security and resiliency. ***Policy issue:*** Washington and several other states are breaking new ground by explicitly requiring utilities to help remedy longstanding environmental and socioeconomic inequities.¹³ This raises important questions as to what constitutes “vulnerable populations,” “highly-impacted communities,” and “equitable distribution.” It also raises questions as to how much retail rates should be raised in order to address these inequities, and how those rate increases should be distributed among residential, commercial, and industrial customer classes.

¹² For comparison, California excludes hydroelectric facilities with more than 30 MW of capacity, and Nevada excludes hydropower facilities with more than 30 MW of capacity placed in service before 1997. Cal. Pub. Util. Code § 399.12(e), (h) (West 2020); Nev. Rev. Stat. Ann. § 704.7811 (2019). Colorado includes new hydroelectric facilities with a nameplate rating of 10 MW or less, and hydro facilities in existence on January 1, 2005 with a nameplate rating of 30 MW or less. Colo. Rev. Stat. Ann. § 40-2-124(1)(a)(VII) (West 2019). New Mexico allows all hydropower facilities brought online after 2007 to qualify as renewable. N.M. Stat. Ann. § 62-16-3 (2019).

¹³ The Virginia Clean Economy Act (2020) requires that certain revenues from the state’s RPS program be directed to job training and clean energy programs in “historically economically disadvantaged communit[ies]”, which are broadly defined to include (i) any community in which a majority of the population are people of color, or (ii) a low-income geographic area. Va. Code Ann. § 56-576 (West 2020). California’s statute requires, “[i]n soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases.” Cal. Pub. Util. Code § 399.13(b) (West 2020). The New York Climate Leadership and Community Protection Act requires that disadvantaged communities “receive no less than thirty-five percent of the overall benefits of spending on clean energy and energy efficiency programs, projects or investments.” N.Y. Envtl. Conserv. Law § 75-0117 (Mckinney 2020).

In the District of Columbia, the Solar for All program aims to bring the benefits of solar energy to 100,000 low-to-moderate income families by installing solar on single family homes and developing community solar projects to benefit renters and residents in multi-family buildings. See <https://doee.dc.gov/node/1226501>.

Direct Access Customers. Large retail customers that purchase electricity directly from the market must comply with the GHG neutrality requirement. ***Policy issue:*** Many large corporations are voluntarily moving very quickly to meet all of their energy needs with zero-carbon electricity, a trend that should facilitate utility compliance with state mandates.

Section 5. Milestone III: 100% Non-Emitting Resources or Renewables by 2045. As of January 1, 2045, and each year thereafter, 100% of retail electric sales must come from either non-emitting electric generation or renewable resources. A utility that fails to meet and maintain the Milestone III standard would be required to pay an administrative penalty under section 9, below. In other words, the alternative compliance options available to meet 20% of Milestone II (i.e., unbundled RECs, investment in energy transformation projects, and electricity from an energy recovery facility using municipal solid waste) would not be available for purposes of satisfying Milestone III. Utilities are also required to incorporate the 2045 deadline into their resource planning, which would presumably preclude the future acquisition of electricity from a fossil fuel-fired facility. ***Policy issue:*** There is a growing consensus that utilities must achieve either 100% renewables or zero emissions within the 2040-50 timeframe. For example, like Washington, Virginia’s recent legislation requires its utilities to be 100% carbon-free by 2045.¹⁴

Section 6. Utility Clean Energy Implementation Plans. The model legislation requires IOUs to submit to the state public utility commission (PUC) a clean energy implementation plan for achieving the 2030 and 2045 deadlines, including specific proposed interim targets for energy efficiency, demand response, and renewable energy. The PUC may revise the plan, including establishing more stringent targets than those proposed by the IOU. The plans must also assure that all customers, including vulnerable populations and highly-impacted communities, are benefiting through the equitable distribution of energy and non-energy benefits. ***Policy issue:*** This provision authorizes state PUCs to play a critical role in determining what path utilities take toward achieving the deadlines, and how the benefits of clean energy are distributed across the socioeconomic spectrum. In order to perform this complex task in an effective and timely manner, state PUCs will need sufficient funding.

In Washington, consumer-owned utilities (COUs) – which include both cooperatives and municipal utilities – are required to follow the same process except that they submit their clean energy implementation plan to their own governing body, which must adopt the plan following a public meeting. The plan is then submitted to the Commerce Department and made available to the public, but the Department is not authorized to change or enforce the plan.¹⁵ To the extent that a state’s PUC regulates resource planning by COUs, as well as IOUs, these additional provisions in the model legislation may be unnecessary.

Cost Cap. As mentioned above, both IOUs and COUs are deemed to be in compliance with the 2030 and 2045 GHG milestones if, over a four-year compliance period, the average annual incremental cost of meeting the milestones equals a 2% increase in the utility’s weather-

¹⁴ Va. Code Ann. § 56-585.5.B.3 (West 2020). Colorado’s goal is a 90% GHG reduction (from 2005 levels) by 2050. Colo. Rev. Stat. Ann. § 25-7-102(2)(g) (West 2019). New Jersey requires 50% renewables by 2030. N.J. Stat. § 48:3-87(d)(2) (West 2020).

¹⁵ Under Washington law, COUs include public utility districts, municipal utilities, and non-profit cooperatives. COUs are largely self-regulated, accountable to their elected governing body. Although they are subject to limited oversight by the state’s Commerce Department, they are exempt from regulation by the Commission.

adjusted sales revenue for electric operations above the previous year. All costs included in the determination of cost impact must be directly attributable to actions necessary to comply with the standards. ***Policy issue:*** The obvious advantage of a cost cap is that it can help avoid significant rate increases as a result of the legislation. Disadvantages include the difficulty in calculating the incremental cost of compliance, thereby creating the potential for manipulation.¹⁶

Section 7. Calculation of GHG Content. Under the model legislation, all utilities must provide to the appropriate state agency or agencies a calculation of the GHG content of their fuel sources.

Section 8. Report to the Legislature Regarding Implementation. Within four years of the date of enactment, and at least every four years thereafter, the relevant state agencies must submit a report to the legislature evaluating the act's implementation in terms of barriers to implementation, public health and environmental benefits, system reliability, and affordability, among other matters. ***Policy issue:*** the model legislation suggests language regarding the timing and scope of agency reports, but each legislature should craft language that reflects the facts, circumstances, and policy goals of that state. Specifically, the timing should reflect key implementation milestones (providing sufficient time to make course corrections following receipt of a report), and the scope should reflect the issues that are most likely to be problematic in that state.

Section 9. Penalties. Under the model legislation, an IOU that fails to meet Milestones I, II, or III must pay an administrative penalty for each MWh of electricity used to meet load that is not from a renewable or non-emitting resource. The penalty is \$100 for each MWh, multiplied by 1.5 for coal-fired resources, 0.84 for gas-fired peakers, and 0.60 for gas-fired combined-cycle power plants.¹⁷ As to Milestone II (which applies from 2030 until 2045) paying the penalty is one of the alternative means of complying with up to 20% of the GHG neutrality standard (along with unbundled RECs, investment in energy transformation projects, and electricity from an energy recovery facility using municipal solid waste). ***Policy issue:*** the use of penalties (as to amount,

¹⁶ Different states use various cost containment mechanisms, including alternative compliance payments (ACPs), caps on rate impacts or revenue requirements (gross or net), caps on RPS surcharges, renewable energy contract price caps, financial penalties, and regulatory oversight of procurement. According to the Lawrence Berkeley National Laboratory, the size of cost caps varies widely (typically less than 10% of retail electricity bills, but are higher in several states with aggressive targets, such as the District of Columbia and Maine). See Galen Barbose, *U.S. Renewables Portfolio Standards 2019 Annual Status Update*, Lawrence Berkeley National Lab. (July 2019), https://eta-publications.lbl.gov/sites/default/files/rps_annual_status_update-2019_edition.pdf. In California, cost caps are determined by the PUC for each electrical corporation. Cal. Pub. Util. Code §§ 399.15(c)-(e) (West 2020). Maine law addresses costs concerns by offering an ACP that utilities may pay instead of satisfying their obligations; in addition, it allows the Maine PUC to suspend, in part, the requirements under certain conditions (e.g., if the use of RECs and the ACP would burden electricity customers). See Me. Rev. Stat. Ann. tit. 35-A §§ 3210(3-A)(B), (3-B)(B), and (9) (2020). The District of Columbia also utilizes ACPs, including a separate Solar ACP (SACP) for its solar-specific requirements. See https://www.srectrade.com/markets/rps/srec/district_of_columbia#:~:text=The%20Solar%20Alternative%20Compliance%20Payment,declining%20thereafter%2C%20as%20shown%20below. (Note: the SACP is \$500/MWh in 2020). Other states, including Virginia, Nevada, New Mexico, New York, and Hawaii, have no cost caps, and the same is true for Puerto Rico.

¹⁷ For comparison, the Virginia Clean Economy Act imposes a penalty of \$45 per MWh for each year of non-compliance.

timing, and exceptions) to incentivize compliance is a key variable that should be tailored to the facts, circumstances, and policy goals of each state.

Under the model legislation, the Commission may temporarily relieve an IOU of an administrative penalty if it finds that compliance with the 2030 standard is likely to compromise the utility's ability to comply with NERC reliability standards, or would violate prudent utility practice for assuring resource adequacy, or non-compliance is due to reasons beyond the utility's control. Causes beyond the utility's control could include a natural disaster, an inability to acquire sufficient transmission capacity to move electricity from non-emitting electric generation or renewable resources to load, or the failure of a third party to meet contractual obligations to the utility. An IOU must notify its retail electric customers if it pays an administrative penalty, but not if the administrative penalty is paid as an alternative compliance payment with respect to the 20% allowed until 2045. Moneys collected are to be deposited into a specified state account, such as (in Washington's case) an account for low-income weatherization and structural rehabilitation assistance.

In Washington, the process is similar for COUs, but with a couple differences. Rather than seeking relief from the Commission, the COU's governing board must itself find that one or more of the above-described extenuating circumstances exist, and then submit a plan to the Commerce Department demonstrating how it intends to achieve full compliance. While in the process of achieving full compliance, the COU is relieved of penalties if the State Auditor finds that the COU has properly issued a temporary exemption, and the state Attorney General is charged with enforcement if the COU fails to comply with the conditions of a temporary exemption. To the extent that the state PUC regulates resource planning for COUs, as well as IOUs, these additional provisions in the model act are unnecessary.

Section 10. Rulemaking. The model legislation authorizes the adoption of implementing regulations by the relevant state agencies.

Section 11. Assistance to Low-Income Households. Utilities must fund energy assistance programs for low-income households within two years after the date of enactment, with priority given to households with a high energy burden. Like CETA, the model legislation also requires outreach strategies to encourage the participation of eligible households, including consultation with community-based organizations and Indian tribes, and comprehensive enrollment campaigns that are linguistically and culturally appropriate to the vulnerable populations they serve.

Section 12. Integration with Regional Energy Markets and Climate Change Programs. The model legislation mandates the relevant state agency or agencies to convene a stakeholder work group to examine the integration of the new law with electricity markets and climate change programs in the surrounding region. In particular, the work group is to assess the compatibility of model legislation with a regional cap-and-trade program. **Policy issue:** In the absence of federal legislation, the creation of effective regional approaches to reducing GHG

emissions is very challenging, due largely to Constitutional constraints and an inability to resolve governance issues.¹⁸

Section 13. Social Cost of Carbon. Like CETA, the model legislation requires electric utilities to incorporate the social cost of carbon into their conservation targets and resource procurement processes. The social cost of carbon is an estimate, in dollars, of the economic damage that would result from emitting one additional ton of GHGs into the atmosphere. The social cost of carbon puts the effects of climate change into economic terms to help policymakers and other decision makers understand the economic impacts of decisions that would increase or decrease emissions. The model legislation adopts the federal methodology for establishing the social cost of carbon based on Executive Order No. 12866, issued by President Clinton in 1993, but which was repealed by President Trump in a 2017 Executive Order. Under the repealed federal methodology, carbon was assessed at \$40 per metric ton in 2017, but that figure will almost certainly increase in the coming decades as the impacts of climate change become more evident. ***Policy issue:*** the requirement to incorporate the social cost of carbon into conservation and resource acquisition decisions is very significant because conservation and renewables are much more economic when compared to a fossil-fuel generating facility that bears the full environmental cost of its GHG emissions.¹⁹

Section 14. Integrated Resource Planning. A utility's IRP must facilitate compliance with the model legislation, using a social cost of carbon to assess conservation, energy efficiency, and generating options. The IRP must also address ways to increase the benefits and reduce the public health and environmental burdens on vulnerable populations and highly-impacted communities.

¹⁸ For example, western states have attempted for at least a decade to create a carbon trading program known as the Western Climate Initiative, but the effort has largely foundered, in part due to tensions between the Commerce Clause and the perceived need to regulate out-of-state generators. In contrast, the Virginia Clean Economy Act (2020) authorizes the state to join the Regional Greenhouse Gas Initiative (RGGI), a regional carbon trading program that avoids Commerce Clause challenges by not regulating out-of-state generators, which limits its effectiveness. Va. Code Ann. § 56-579 (West 2020). The California Energy and Pollution Reduction Act of 2015 (SB 350) was intended to facilitate the evolution of California's Independent System Operator into a regional organization to promote the development of regional electricity transmission markets in the western states. Cal. Pub. Util. Code § 359 (West 2020). However, progress towards regionalization in the west has been stymied by disagreements of over governance. See CAISO, *Exploring Regional Solutions for a Green Grid*, <http://www.caiso.com/informed/Pages/RegionalSolutions.aspx>.

¹⁹ Other states have continued to use the social cost of carbon despite the Trump Administration repeal. <https://insideclimatenews.org/news/11082017/states-climate-change-policy-calculate-social-cost-carbon>. For example, the Virginia Clean Economy Act (2020) requires the state PUC to determine the social cost of carbon, and orders utilities to include the social cost of carbon in any application to construct a new generating facility. Va. Code Ann. § 56-585.1 (West 2020). The New York Climate Leadership and Community Protection Act requires the development of a social cost of carbon for use by state agencies. N.Y. Evtl. Conserv. Law § 75-0113 (Mckinney 2020). California statutory law does not require use of the social cost of carbon, but the California PUC issued an order in 2019 requiring the use of the social cost of carbon for evaluating distributed energy resources. Similarly, the California Air Resources Board used the social cost of carbon and the social cost of methane in the scoping plan for the state's updated climate change policy.

Section 15. Designation of Communities Highly Impacted by Fossil Fuel Pollution and Climate Change. The relevant state agency must develop a cumulative impact analysis to designate communities highly impacted by fossil fuel pollution and climate change.

Section 16. Severability. Self-explanatory.

ATTACHMENT A

MODEL STATE LEGISLATION TO DECARBONIZE THE GENERATION OF ELECTRICITY

Section 1. Findings and Purposes

(1) The legislature finds that [insert state name] must address the impacts of climate change by leading the transition to a clean energy economy. One way in which [insert state name] must lead this transition is by transforming its energy supply, modernizing its electricity system, and ensuring that the benefits of this transition are broadly shared throughout the state.

(2) We are at a critical juncture for transforming our electricity system. It is the policy of the state to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045. In implementing this act, the state must ensure that all customers are benefiting from the transition to a clean energy economy, and provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers.

(3) The transition to one hundred percent clean energy is underway, but must happen faster than our current policies can deliver. Absent significant and swift reductions in greenhouse gas emissions, climate change poses immediate threats to our economy, health, safety, and national security. The costs of energy efficiency measures and clean energy technologies continue to fall, and are, in many cases, competitive or even cheaper than conventional energy sources.

(4) The legislature finds that this act will promote energy conservation and energy efficiency; create high-quality jobs in the clean energy sector; encourage the development of clean energy resources; maintain safe and reliable electricity to all customers at stable and affordable rates; and protect the quality of our air and water.

(5) The legislature declares that electric utilities have an important role to play in this transition, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this act. In combination with new technology and emerging opportunities for customers, this act will spur transformational change in the electric utility industry.

(6) The legislature finds that clean energy serves the public interest by providing both short-term and long-term public health, economic, and environmental benefits; by reducing the environmental burdens on vulnerable populations and highly-impacted communities; and by increasing the resiliency and reliability of our electricity supply.

Section 2. Definitions

The definitions in this section apply throughout this act unless the context clearly requires otherwise.

(1) “Affected market customer” is a customer of an investor-owned utility who becomes a market customer after the effective date of this act.

(2) “Allocation of electricity” means, for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility’s retail electricity consumers that are located in this state.

(3) “Alternative compliance payment” means the payment established in section 9(2) of this act.

(4) “Attorney general” means the [insert state name] office of the attorney general.

(5) “Auditor” means: (a) The [insert state name] auditor’s office or its designee for utilities under its jurisdiction under this act that are consumer-owned utilities; or (b) an independent auditor selected by a utility that is not under the jurisdiction of the state auditor and is not an investor-owned utility.

(6) “Biomass energy” includes: electric energy generated from (i) organic by-products of pulping and the wood manufacturing process; (ii) animal manure; (iii) solid organic fuels from wood; (iv) forest or field residues; (v) untreated wooden demolition or construction debris; (vi) food waste and food processing residuals; (vii) liquors derived from algae; (viii) dedicated energy crops; and (ix) yard waste. “Biomass energy” does not include: electric energy generated from (i) wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (ii) wood from old growth forests; or (iii) municipal solid waste.

(7) “Carbon dioxide equivalent” means a metric measure used to compare the emissions from various greenhouse gases based upon their global warming potential.

(8) “Coal-fired resource” means a facility that uses coal-fired generating units, or that uses units fired in whole or in part by coal as feedstock, to generate electricity. “Coal-fired resource” does not include an electric generating facility that is included as part of a limited duration wholesale power purchase, not to exceed one month, made by an electric utility for delivery to retail electric customers that are located in this state for which the source of the power is not known at the time of entry into the transaction to procure the electricity.

(9) “Commission” means the [insert name of the state public utility commission].

(10) “Conservation and efficiency resources” means any reduction in electric power consumption that results from increases in the efficiency of energy use, production, transmission, or distribution.

(11) “Consumer-owned utility” means a municipal electric utility formed under [insert statutory cross-reference], a public utility district formed under [insert statutory cross-reference], an irrigation district formed under [insert statutory cross-reference], a cooperative formed under [insert statutory cross-reference], or a mutual corporation or association formed under [insert statutory cross-reference], that is engaged in the business of distributing electricity to more than one retail electric customer within the state.

(12) “Demand response” means changes in electric usage by demand-side resources from normal consumption levels, including in response to changes in the price of electricity, or incentive payments designed to induce lower retail customer electricity use at times of high wholesale market prices or when system reliability is jeopardized. “Demand response” may include measures to increase or decrease electricity production on the customer’s side of the meter in response to incentive payments.

(13) “Department” means [insert name of state agency with jurisdiction over COUs, if other than the state PUC].

(14) “Distributed energy resource” means a non-emitting electric generation or renewable resource or program that reduces electric demand, manages the level or timing of electricity consumption, or provides storage, electric energy, capacity, or ancillary services to an electric utility and that is located on the distribution system, any subsystem of the distribution system, or behind the customer meter, including conservation and energy efficiency.

(15) “Electric utility” or “utility” means a consumer-owned utility or an investor-owned utility.

(16) “Energy assistance” means a program undertaken by a utility to reduce the household energy burden of its customers, including, but not limited to, weatherization, conservation and efficiency services, and monetary assistance, such as a grant program or discounts for low-income households, intended to lower a household’s energy burden. “Energy assistance” may include direct customer ownership of distributed energy resources if ownership would achieve a reduction in the household energy burden for the customer more cost-effectively than other available conservation and demand-side measures.

(17) “Energy assistance need” means the amount of assistance necessary to achieve a level of household energy burden established by the Department or Commission.

(18) “Energy burden” means the share of annual household income used to pay annual home energy bills.

(19)(a) “Energy transformation project” means a project or program that provides energy-related goods or services, other than the generation of electricity; results in a reduction of fossil fuel consumption; and provides benefits to the customers of an electric utility.

(b) “Energy transformation project” may include but is not limited to:

(i) Home weatherization or other energy efficiency measures, including market transformation for energy efficiency products, in excess of other obligations in effect on the effective date of this act;

(ii) Support for electrification of the transportation sector including, but not limited to:

(A) Equipment on an electric utility’s transmission and distribution system to accommodate electric vehicle connections, as well as smart grid systems that enable electronic

interaction between the electric utility and charging systems, and facilitate the utilization of vehicle batteries for system needs;

(B) Incentives for the sale or purchase of electric vehicles, both battery and fuel cell powered, as authorized under state or federal law;

(C) Incentives for the installation of charging equipment for electric vehicles;

(D) Incentives for the electrification of vehicle fleets utilizing a battery or fuel cell for electric supply;

(E) Incentives to install and operate equipment to produce or distribute renewable hydrogen; and

(F) Incentives for renewable hydrogen fueling stations;

(iii) Investment in distributed energy resources and grid modernization to facilitate distributed energy resources and improved grid resilience;

(iv) Investments in equipment for renewable natural gas processing, conditioning, and production, or equipment or infrastructure used solely for the purpose of delivering renewable natural gas for consumption or distribution;

(v) Contributions to self-directed investments in the following measures to serve the sites of large industrial gas and electrical customers: (A) conservation; (B) new renewable resources; (C) behind-the-meter technology that facilitates demand response cooperation to reduce peak loads; (D) infrastructure to support electrification of transportation needs, including battery and fuel cell electrification; or (E) renewable natural gas processing, conditioning, or production; and

(vi) Projects and programs that achieve energy efficiency and emission reductions in the agricultural sector, including bioenergy and renewable natural gas projects.

(20) “Fossil fuel” means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such a material.

(21) “Governing body” means the council of a city or town; the commissioners of an irrigation district, municipal electric utility, or public utility district; or the board of directors of an electric cooperative or mutual association that has the authority to recommend, set, or approve rates.

(22) “Greenhouse gas” includes carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and any other gas or gases designated by the [insert state air quality agency] by rule.

(23) “Greenhouse gas content calculation” means a calculation expressed in carbon dioxide equivalent and made by the [insert state air quality agency] for the purposes of determining the emissions from the complete combustion or oxidation of fossil fuels and the

greenhouse gas emissions in electricity for use in calculating the greenhouse gas emissions content in electricity.

(24) “Highly-impacted community” means a community designated by the [insert state agency responsible for public health] based on cumulative impact analyses conducted pursuant to section 15 of this act, or a community located in census tracts that are fully or partially on “Indian country” as defined in 18 U.S.C. Sec. 1151.

(25) “Investor-owned utility” means a company owned by investors that is engaged in distributing electricity to more than one retail electric customer in the state.

(26) “Low-income” means household incomes as defined by [insert relevant state agency], provided that the definition may not exceed the higher of eighty percent of area median household income or two hundred percent of the federal poverty level, adjusted for household size.

(27) “Market customer” means a non-residential retail electric customer of an electric utility that: (i) purchases electricity from an entity or entities other than the utility with which it is directly interconnected; or (ii) generates electricity to meet one hundred percent of its own needs.

(27) “Natural gas” means naturally occurring mixtures of hydrocarbon gases and vapors consisting principally of methane, whether in gaseous or liquid form, including methane clathrate. “Natural gas” does not include renewable natural gas or the portion of renewable natural gas when blended into other fuels.

(28) “Non-emitting electric generation” means electricity from a generating facility or a resource that provides electric energy, capacity, or ancillary services to an electric utility and that does not emit greenhouse gases as a by-product of energy generation. “Non-emitting electric generation” does not include renewable resources.

(29) “Non-power attributes” means all environmentally-related characteristics, exclusive of energy, capacity, reliability, and other electrical power service attributes, that are associated with the generation of electricity, including but not limited to the facility’s fuel type, geographic location, vintage, qualification as a renewable resource, and avoided emissions of pollutants to the air, soil, or water, and avoided emissions of carbon dioxide and other greenhouse gases. “Non-power attributes” does not include any aspects, claims, characteristics, and benefits associated with the on-site capture and destruction of methane or other greenhouse gases at a facility through a digester system, landfill gas collection system, or other mechanism, which may be separately marketable as greenhouse gas emission reduction credits, offsets, or similar tradable commodities.

(30) “Qualified transmission line” means an overhead transmission line that is: (a) designed to carry a voltage in excess of one hundred thousand volts; (b) owned in whole or in part by an investor-owned utility; and (c) primarily or exclusively used by such an investor-owned utility as of the effective date of this act to transmit electricity generated by a coal-fired resource.

(31) “Renewable energy credit” means a tradable certificate of proof of one megawatt-hour of a renewable resource. The certificate includes all of the non-power attributes associated with that one megawatt-hour of electricity and the certificate is verified by a renewable energy credit tracking system selected by the [insert relevant state agency].

(32) “Renewable hydrogen” means hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process.

(33) “Renewable natural gas” means a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters.

(34) “Renewable resource” means: (a) water; (b) wind; (c) solar energy; (d) geothermal energy; (e) renewable natural gas; (f) renewable hydrogen; (g) wave, ocean, or tidal power; (h) biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests; or (i) biomass energy.

(35) “Retail electric customer” means a person or entity that purchases electricity from any electric utility for ultimate consumption and not for resale. “Retail electric customer” does not include any person or entity that purchases electricity exclusively from carbon-free and eligible renewable resources pursuant to a special contract with an investor-owned utility approved by an order of the Commission prior to the effective date of this act.

(36) “Retail electric load” means the amount of megawatt-hours of electricity delivered in a given calendar year by an electric utility to its [insert state name] retail electric customers. “Retail electric load” does not include: (a) megawatt-hours delivered from qualifying facilities under the federal Public Utility Regulatory Policies Act of 1978, P.L. 95–617, in operation prior to the effective date of this section, provided that no entity other than the electric utility can make a claim on delivery of the megawatt-hours from those resources; or (b) megawatt-hours delivered to an electric utility’s system from a renewable resource through a voluntary renewable energy purchase by a retail electric customer of the utility in which the renewable energy credits associated with the megawatt-hours delivered are retired on behalf of the retail electric customer.

(37) “Thermal renewable energy credit” means, with respect to a facility that generates electricity using biomass energy that also generates thermal energy for a secondary purpose, a renewable energy credit that is equivalent to three million four hundred twelve thousand (3,412,000) British thermal units of energy used for such secondary purpose.

(38) “Unbundled renewable energy credit” means a renewable energy credit that is sold, delivered, or purchased separately from electricity. All thermal renewable energy credits are considered unbundled renewable energy credits.

(39) “Unspecified electricity” means an electricity source for which the fuel attribute is unknown or has been separated from the energy delivered to retail electric customers.

(40) “Vulnerable populations” means communities that experience a disproportionate cumulative risk from environmental burdens due to: (a) adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and

health care, and linguistic isolation; and (b) sensitivity factors, such as low birth-weight and higher rates of hospitalization.

Section 3. Milestone I: No Use of Coal-Fired Resources by End of 2025

(1)(a) On or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity.

(b) The Commission shall allow in electric rates all decommissioning and remediation costs prudently incurred by an investor-owned utility with respect to a coal-fired resource.

(2) To address transition costs associated with existing power plants, the Commission must accelerate depreciation schedules for any coal-fired resource to a date no later than December 31, 2025. The Commission may accelerate the depreciation schedule for any qualified transmission line owned by an investor-owned utility when the Commission finds the qualified transmission line is no longer used and useful and there is no reasonable likelihood that the qualified transmission line will be utilized in the future. The adjusted depreciation schedule must require that a qualified transmission line be fully depreciated on or before December 31, 2025.

(3) The Commission shall allow in rates amounts on an investor-owned utility's books that the Commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that has been retired from service when:

(a) The retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, inability to procure or use fuel, termination or expiration of any ownership, or an operation agreement affecting such a fossil fuel generating resource; or

(b) The Commission finds that the retirement is in the public interest.

(4) An electric utility that fails to comply with the requirements of subsection (1)(a) of this section must pay the administrative penalty established under section 9(1) of this act, except as otherwise provided in this act.

Section 4. Milestone II: GHG Neutrality of all Retail Electric Sales by 2030

(1) All retail sales of electricity to [insert state name] retail electric customers shall be greenhouse gas neutral by January 1, 2030.

(a) **Demonstration of Compliance.** For the four-year compliance period beginning January 1, 2030, and for each multiyear compliance period thereafter through December 31, 2044, an electric utility must demonstrate its compliance with this standard using a combination of non-emitting electric generation and electricity from renewable resources, or alternative compliance options, as provided in this section. To achieve compliance with this standard, an electric utility must: (i) pursue all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load; and (ii) use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utility's retail electric loads over each multiyear compliance period. An electric

utility must achieve compliance with this standard for the following compliance periods: January 1, 2030, through December 31, 2033; January 1, 2034, through December 31, 2037; January 1, 2038, through December 31, 2041; and January 1, 2042, through December 31, 2044.

(b) **Alternative Compliance Options.** Through December 31, 2044, an electric utility may satisfy up to twenty percent of its compliance obligation under subsection (1) of this section through any combination of the following alternative compliance options:

(i) Making an alternative compliance payment under section 9(2) of this act;

(ii) Using unbundled renewable energy credits produced from eligible renewable resources, provided that there is no double counting of any non-power attributes associated with renewable energy credits within [insert state name] or programs in other jurisdictions, as follows:

(A) Investing in energy transformation projects, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or

(B) Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility is operated in compliance with federal laws and regulations and meets state air quality standards. An electric utility may only use electricity from such an energy recovery facility if the [insert relevant state agency] determines that electricity generation at the facility provides a net reduction in greenhouse gas emissions compared to any other available waste management best practice. The determination must be based on a life-cycle analysis comparing the energy recovery facility to other technologies available in the jurisdiction in which the facility is located for the waste management best practices of waste reduction, recycling, composting, and minimizing the use of a landfill.

(c) Electricity from renewable resources used to meet the standard under subsection (1) of this section must be verified by the retirement of renewable energy credits. Renewable energy credits must be tracked and retired in the tracking system selected by the [insert relevant state agency].

(d) Non-emitting electric generation used to meet the standard under subsection (1) of this section must be generated during the compliance period and must be verified by documentation that the electric utility owns the non-power attributes of the electricity generated by the non-emitting electric generation resource.

(2) **Energy Transformation Projects.** Investments in energy transformation projects used to satisfy an alternative compliance option provided under subsection (1)(b) of this section must use criteria developed by the [insert relevant state agency or agencies]. For the purpose of crediting an energy transformation project toward the standard in subsection (1) of this section, the [insert relevant state agency or agencies] shall establish a conversion factor of emissions reductions resulting from energy transformation projects to megawatt-hours of electricity from non-emitting electric generation that is consistent with the emission factors for unspecified electricity, or for energy transformation projects in the transportation sector, consistent with

default emissions or conversion factors established by other jurisdictions for clean alternative fuels. Emissions reductions from energy transformation projects must be:

- (a) Real, specific, identifiable, and quantifiable;
 - (b) Permanent: The [insert relevant state agency] must look to other jurisdictions in setting this standard and make a reasonable determination on length of time;
 - (c) Enforceable by the state of [insert state name];
 - (d) Verifiable;
 - (e) Not required by another statute, rule, or other legal requirement; and
 - (f) Not reasonably assumed to occur absent investment, or if an investment has already been made, not reasonably assumed to occur absent additional funding in the near future.
- (3) Energy transformation projects must be associated with the consumption of energy in [insert state name] and must not create a new use of fossil fuels that results in a net increase of fossil fuel usage.
- (4) The compliance eligibility of energy transformation projects may be scaled or prorated by an approved protocol in order to distinguish effects related to reductions in electricity usage from reductions in fossil fuel usage.
- (5) Any compliance obligation fulfilled through an investment in an energy transformation project is eligible for use only: (a) by the electric utility that makes the investment; or (b) if the investment is made by the [insert name of the relevant federal Power Marketing Administration, if any], by electric utilities that are preference customers of the [insert name of the relevant federal Power Marketing Administration, if any]. An electric utility making an investment in partnership with another electric utility or entity may claim credit proportional to its share invested in the total project cost.
- (6) An electric utility that fails to meet the requirements of this section shall pay the administrative penalty established under section 9(1) of this act, except as otherwise provided in this act.
- (7) In complying with this section, an electric utility shall ensure that all customers are benefiting from the transition to clean energy through the equitable distribution of energy and non-energy benefits and reduction of burdens to vulnerable populations and highly-impacted communities; through short-term and long-term public health and environmental benefits; and through energy resiliency and reliability.
- (8) Affected market customers shall comply with the standard established under subsection (1) of this section; provided that a market customer that purchases electricity exclusively from carbon-free resources and eligible renewable resources pursuant to a special contract with an investor-owned utility approved by the Commission prior to the effective date of

this act shall be subject to the requirements of such order and not to the standard established under subsection (1) of this section.

Section 5. Milestone III: 100% Non-Emitting Resources by 2045.

(1) Non-emitting electric generation and electricity from renewable resources shall supply one hundred percent of all sales of electricity to [insert state name] retail electric customers by January 1, 2045. By January 1, 2045, and each year thereafter, each electric utility must demonstrate its compliance with this standard using a combination of non-emitting electric generation and electricity from renewable resources.

(2) Each electric utility must incorporate subsection (1) of this section into all relevant planning and resource acquisition practices including, but not limited to, resource planning; the construction or acquisition of property, including electric generating facilities; and the provision of electricity service to retail electric customers.

(3) In planning to meet projected demand consistent with the requirements of subsection (2) of this section, an electric utility must pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response. In making new investments, an electric utility must, to the maximum extent feasible:

(a) Achieve targets at the lowest reasonable cost, considering risk;

(b) Consider acquisition of existing renewable resources; and

(c) In the acquisition of new resources constructed after the effective date of this section, rely on renewable resources and energy storage, insofar as doing so is consistent with (a) of this subsection.

(4) The [insert relevant state agencies] must incorporate this section into all relevant planning and utilize all programs authorized by statute to achieve subsection (1) of this section.

(5) An electric utility that fails to meet the requirements of this section shall pay the administrative penalty established under section 9(1) of this act, except as otherwise provided in this act.

(6) Affected market customers must comply with the standard established under subsection (1) of this section; provided that any market customer that purchases electricity exclusively from carbon-free resources and eligible renewable resources pursuant to a special contract with an investor-owned utility approved by the Commission prior to the effective date of this act shall be subject to the requirements of such order and not to the standard established under subsection (1) of this section.

Section 6. Utility Implementation Plans to Achieve Milestones

(1)(a) Within two years after the date of enactment, and every four years thereafter, each utility subject to resource planning regulation by the Commission must develop and submit to the Commission:

(i) A four-year clean energy implementation plan for the standards established under sections 4(1) and 5(1) of this act that proposes specific targets for energy efficiency, demand response, and renewable energy; and

(ii) Proposed interim targets for meeting the standard under section 4(1) of this act during the years prior to 2030 and between 2030 and 2045.

(b) A utility's clean energy implementation plan must:

(i) Be informed by the utility's clean energy action plan developed under section 14(g) of this act;

(ii) Be consistent with subsection (3) of this section; and

(iii) Identify specific actions to be taken by the utility over the next four years, consistent with the utility's long-range integrated resource plan and resource adequacy requirements, that demonstrate progress toward meeting the standards under sections 4(1) and 5(1) of this act and the interim targets proposed under (a)(ii) of this subsection. The specific actions identified must be informed by the utility's historic performance under median water conditions and resource capability and by the utility's participation in centralized markets. In identifying specific actions in its clean energy implementation plan, the utility may also take into consideration any significant and unplanned loss or addition of load it experiences.

(c) The Commission, after a hearing, must by order approve, reject, or approve with conditions a clean energy implementation plan and interim targets for any utility subject to its resource planning jurisdiction. The Commission may, in its order, recommend or require more stringent targets than those proposed by the utility. The Commission may periodically adjust or expedite timelines if it can be demonstrated that the targets or timelines can be achieved in a manner consistent with the following:

(i) Maintaining and protecting the safety, reliable operation, and balancing of the electric system;

(ii) Planning to meet the standards at the lowest reasonable cost, considering risk;

(iii) Ensuring that all customers are benefiting from the transition to clean energy: through the equitable distribution of energy and non-energy benefits and the reduction of burdens to vulnerable populations and highly-impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy resiliency and reliability; and

(iv) Ensuring that no customer or class of customers is unreasonably harmed by any resulting increases in the cost of utility-supplied electricity as may be necessary to comply with the standards.

(2)(a) Any consumer-owned utility not subject to resource planning jurisdiction of the Commission shall, within two years of the date of enactment, and every four years thereafter, submit to the [insert agency with jurisdiction over COU resource planning] a four-year clean

energy implementation plan for the standards established under sections 4(1) and 5(1) of this act that:

(i) Proposes interim targets for meeting the standard under section 4(1) of this act during the years prior to 2030 and between 2030 and 2045, as well as specific targets for energy efficiency, demand response, and renewable energy;

(ii) Is informed by the consumer-owned utility's clean energy action plan developed under section 14(g) of this act;

(iii) Is consistent with subsection (3) of this section; and

(iv) Identifies specific actions to be taken by the consumer-owned utility over the next four years, consistent with the utility's long-range resource plan and resource adequacy requirements, that demonstrate progress towards meeting the standards under sections 4(1) and 5(1) of this act and the interim targets proposed under (a)(i) of this subsection. The specific actions identified must be informed by the consumer-owned utility's historic performance under median water conditions and resource capability and by the consumer-owned utility's participation in centralized markets. In identifying specific actions in its clean energy implementation plan, the consumer-owned utility may also take into consideration any significant and unplanned loss or addition of load it experiences.

(b) Except where the Commission regulates consumer-owned utility resource planning, the governing body of each consumer-owned utility must, after a public meeting, consider the consumer-owned utility's proposed clean energy implementation plan and adopt a clean energy implementation plan for the consumer-owned utility. The clean energy implementation plan must be submitted to the [insert agency with jurisdiction over COU resource planning] and made available to the public. The governing body may adopt more stringent targets than those proposed by the consumer-owned utility and periodically adjust or expedite timelines if it can be demonstrated that such targets or timelines can be achieved in a manner consistent with the following:

(i) Maintaining and protecting the safety, reliable operation, and balancing of the electric system;

(ii) Planning to meet the standards at the lowest reasonable cost, considering risk;

(iii) Ensuring that all customers are benefiting from the transition to clean energy: through the equitable distribution of energy and non-energy benefits and reduction of burdens to vulnerable populations and highly-impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency; and

(iv) Ensuring that no customer or class of customers is unreasonably harmed by any resulting increases in the cost of utility-supplied electricity as may be necessary to comply with the standards.

(3)(a) A utility shall be considered to be in compliance with the standards under sections 4(1) and 5(1) of this act if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a two percent increase of the utility's weather-adjusted sales revenue to customers for electric operations above the previous year. All costs included in the determination of cost impact must be directly attributable to actions necessary to comply with the requirements of sections 4 and 5 of this act.

(b) If a utility relies on (a) of this subsection as a basis for compliance with the standard under section 4(1) of this act, then it must demonstrate that it has maximized investments in renewable resources and non-emitting electric generation prior to using alternative compliance options allowed under section 4(1)(b) of this act.

(4) The Commission, for utilities over which it has resource planning jurisdiction, and the [insert relevant state agency], for utilities outside the Commission's resource planning jurisdiction, must adopt rules establishing the methodology for calculating the incremental cost of compliance under this section, as compared to the cost of an alternative lowest reasonable cost portfolio of investments that are reasonably available.

Section 7. Calculation of GHG Content

(1) Each electric utility must provide to the [insert relevant state agency or agencies] its greenhouse gas content calculation in conformance with this section. A utility's greenhouse gas content calculation must be based on the fuel sources that it reports and discloses in compliance with [insert reference to state GHG reporting requirement, if any.]

(2) For unspecified electricity, the utility must use an emissions rate determined, and periodically updated, by the [insert state air quality agency]. The [insert state air quality agency] must adopt an emissions rate for unspecified electricity consistent with the emissions rate established for other markets in the [insert surrounding region].

Section 8. Report to Legislature Regarding Implementation

Within four years of the date of enactment, and at least every four years thereafter, the [insert relevant state agency or agencies] must submit a report to the legislature evaluating the implementation of this act in terms of: (a) barriers to implementing sections [insert sections most likely to pose implementation challenges] of this act; (b) short-term and long-term public health and environmental benefits; (c) system reliability, including resource adequacy, transmission capability, grid security and resilience, and compliance with the reliability standards of the North American Electric Reliability Corporation; (d) affordability, including the effectiveness of this act in assisting low-income households experiencing a high energy burden; (e) potential improvements to the procurement processes of utilities; (f) new or emerging technologies that could be considered to be a renewable resource; and (g) the integration of actions taken pursuant to this act with carbon and electricity markets outside the state.

Section 9. Penalties.

(1)(a) An electric utility or an affected market customer that fails to meet the standards established under sections 3(1), 4(1), or 5(1) of this act shall pay an administrative penalty to the [insert relevant state entity] in the amount of one hundred dollars, times the following multipliers, for each megawatt-hour of electric generation used to meet load that is not electricity from a renewable resource or non-emitting electric generation: (i) 1.5 for coal-fired resources; (ii) 0.84 for gas-fired peaking power plants; and (iii) 0.60 for gas-fired combined-cycle power plants.

(b) Beginning in [two years after the date of enactment], this penalty shall be adjusted on a biennial basis according to the rate of change of the inflation indicator, gross domestic product implicit price deflator, as published by the Bureau of Economic Analysis of the U.S. Department of Commerce or its successor. Beginning in [five years after the date of enactment], the Commission may by rule increase this penalty for utilities subject to its jurisdiction if the Commission determines that doing so will accelerate utilities' compliance with the standards established under this act and that doing so is in the public interest.

(2) Consistent with the requirements of section 4(1)(b) of this act, a utility may satisfy up to twenty percent of its obligation to comply with the standard contained in section 4(1) of this act by using alternative compliance options in lieu of paying the administrative penalty.

(3)(a) The Commission is authorized to impose penalties as provided under this act on any utility subject to its jurisdiction. At the request of a utility subject to its jurisdiction, after a hearing, the Commission may issue an order relieving the utility of its administrative penalty obligation under subsection (1) of this section if it finds that:

(i) After taking all reasonable measures, the utility's compliance with this act is likely to result in conflicts with or compromises to its obligation to comply with the mandatory and enforceable reliability standards of the North American Electric Reliability Corporation, violate prudent utility practice for assuring resource adequacy, or compromise the power quality or integrity of its system; or

(ii) The utility is unable to comply with the standards established in section 3(1), section 4(1), or section 5(1) of this act due to reasons beyond the reasonable control of the utility, as set forth in subsection (6) of this section.

(b) If the Commission issues an order pursuant to (a) of this subsection that relieves a utility of its administrative penalty obligation under subsection (1) of this section, the Commission may issue an order:

(i) Temporarily exempting the utility from the requirements of sections 3(1), 4(1), or 5(1) of this act for an amount of time sufficient to allow the utility to achieve full compliance with the standard;

(ii) Directing the utility to file a progress report to the Commission on achieving full compliance with the standard within six months after issuing the order, or within an amount of time determined to be reasonable by the Commission; and

(iii) Directing the utility to take specific actions to achieve full compliance with the requirements of this act.

(c) A utility may request an extension of a temporary exemption granted under this section. A utility that requests an extension must request an update to the order issued by the Commission under (b) of this subsection.

(4) Subsection (3) of this section does not permanently relieve a utility of its obligation to comply with the requirements of this act.

(5)(a) Unless a consumer-owned utility is subject to regulation by the Commission, the governing body of a consumer-owned utility may authorize a temporary exemption from the standards established under sections 3(1), 4(1), or 5(1) of this act, for an amount of time sufficient to allow the consumer-owned utility to achieve full compliance with the standard, if the governing body finds that:

(i) The consumer-owned utility's compliance with the standard is likely to result in conflicts with or compromises to its obligation to comply with the mandatory and enforceable reliability standards of the North American Electric Reliability Corporation; violate prudent utility practice for assuring resource adequacy; or compromise the power quality or integrity of its system; or

(ii) The consumer-owned utility is unable to comply with the standard due to reasons beyond the reasonable control of the utility, as set forth in subsection (6) of this section; and

(iii) The consumer-owned utility has provided to the [insert state agency with jurisdiction over consumer-owned utilities] a plan demonstrating how it plans to achieve full compliance with the standard, consistent with the findings of the report submitted to the legislature under section 8 of this act.

(b) Upon request by the governing body of a consumer-owned utility, a consumer-owned utility must be relieved of its administrative penalty obligation under subsection (1) of this section if the [insert state agency with jurisdiction over consumer-owned utilities] issues a finding that:

(i) The governing body of the consumer-owned utility has properly issued a temporary exemption under (a) of this subsection for a period of time not to exceed six months; and

(ii) The governing body of the consumer-owned utility has submitted to the [insert state agency with jurisdiction over consumer-owned utilities] a plan to take specific actions to achieve full compliance with the standard, consistent with the findings of the report submitted to the legislature under section 8 of this act.

(c) Upon issuance of a finding by the [insert state agency with jurisdiction over consumer-owned utilities], the consumer-owned utility must submit a progress report to the [insert state agency with jurisdiction over consumer-owned utilities] upon achieving full compliance with the standard within the term authorized in the temporary exemption.

(d) A consumer-owned utility may request an extension of a temporary exemption granted under this subsection, subject to the same requirements as provided in (a) through (c) of this subsection.

(e) The attorney general may bring a civil action in the name of the state for any appropriate civil remedy including, but not limited to, injunctive relief, penalties, costs, and attorneys' fees, to enforce compliance with this act:

(i) Upon the failure of the governing body of a consumer-owned utility to comply with the conditions of a temporary exemption found by the [insert state agency with jurisdiction over consumer-owned utilities] to be properly adopted or extended; or

(ii) Upon failure of the governing body of a consumer-owned utility to comply with a finding by the [insert state agency with jurisdiction over consumer-owned utilities] that a temporary exemption is not properly granted.

(f) This subsection does not permanently relieve a consumer-owned utility of its obligation to comply with the requirements of this act.

(6) Events or circumstances beyond the reasonable control of an electric utility may include but are not limited to (a) weather-related damage; (b) natural disasters; (c) mechanical or resource failure; (d) failure of a third party to meet contractual obligations to the electric utility; (e) actions of governmental authorities that adversely affect the generation, transmission, or distribution of non-emitting electric generation or renewable resources owned or under contract to an electric utility, including condemnation actions by municipal electric utilities, public utility districts, or irrigation districts that adversely affect a utility's ability to meet the standards established in sections 3(1), 4(1), or 5(1) of this act; (f) inability to acquire sufficient transmission to transmit electricity from non-emitting electric generation or renewable resources to load; and (g) substantial limitations, restrictions, or prohibitions on non-emitting electric generation or renewable resources.

(7) An electric utility must notify its retail electric customers within three months of paying the administrative penalty established under subsection (1) of this section. An electric utility is not required to notify its retail electric customers when making a payment in the amount of the administrative penalty as an alternative compliance payment consistent with the requirements of section 4(1)(b) of this act.

(8) Moneys collected under this section must be deposited into an account for [specify state use of penalty moneys; for example, low-income weatherization and related assistance].

(9) For any utility subject to the jurisdiction of the Commission, the Commission shall determine compliance with the requirements of this act.

(10) For consumer-owned utility not subject to the jurisdiction of the Commission, the [insert state agency with jurisdiction over consumer-owned utilities] is responsible for auditing compliance with this act and rules adopted under this act that apply to those utilities, and the attorney general is responsible for enforcing that compliance.

(11) If the report submitted under section 8 of this act demonstrates adverse system reliability impacts from the implementation of sections 4 and 5 of this act, the governor may suspend or delay implementation of this act, or exempt an electric utility from paying the administrative penalty under this section, until system reliability impacts can be addressed. Adverse system reliability impacts may include, but are not limited to, the inability of electric utilities or transmission operators to meet reliability standards mandated by federal or state law and required by prudent utility practices.

Section 10. Rulemaking

(1) It is the intent of the legislature that the Commission and [insert other relevant state agencies] coordinate in developing rules related to process, timelines, and documentation that are necessary for the implementation of this act.

(2) The Commission may adopt rules to ensure the proper implementation and enforcement of this act as it applies to investor-owned utilities and any other utilities over which it has jurisdiction.

(3) To the extent that consumer-owned utilities are beyond the jurisdictional of the Commission, the [insert state agency authorized to regulate consumer-owned utilities] is authorized to adopt rules to ensure the proper implementation and enforcement of this act as it applies to consumer-owned utilities. Nothing in this subsection may be construed to restrict the rate-making authority of the governing body of a consumer-owned utility as otherwise provided by law.

(4) The [insert relevant state agency or agencies] shall adopt rules establishing reporting requirements for electric utilities to demonstrate compliance with this act.

(5) A utility subject to Commission jurisdiction must also report all information required in subsection (4) of this section to the Commission.

(6) A utility must also make reports required in this section available to its retail electric customers.

(7) The [insert relevant state agency] shall adopt rules, in consultation with [insert other relevant state agencies], to establish requirements for energy transformation project investments including, but not limited to, verification procedures, reporting standards, and other matters as necessary.

(8) The [insert relevant state agency] shall adopt rules providing for the measurement and tracking of thermal renewable energy credits that may be used for compliance under section 4 of this act.

(9) Pursuant to the administrative procedure act, [insert cross-reference to state APA], rules necessary for the implementation of this act must be adopted within 18 months of the date of enactment, unless otherwise specified in this act.

Section 11. Assistance to Low-Income Households

(1) It is the intent of the legislature to demonstrate progress toward making energy assistance funds available to low-income households consistent with the policies identified in this section.

(2) Within two years of the date of enactment, each utility shall demonstrate progress in providing energy assistance pursuant to the assessment and plans in subsection (4) of this section. To the extent practicable, priority shall be given to low-income households with a higher energy burden.

(3) Within two years of the date of enactment, the [insert relevant state agency] shall collect and disseminate data that will assist agency and utility efforts to provide energy assistance to low-income households. The [insert relevant state agency] shall update such data on a biennial basis, and make it publicly available.

(a) The aggregated data published by the [insert relevant state agency] shall include, but is not limited to: (i) the estimated number and demographic characteristics of households served by energy assistance for each utility and the dollar value of the assistance; (ii) the estimated level of energy burden and energy assistance need among customers served, accounting for household income and other drivers of energy burden; (iii) housing characteristics including housing type, home vintage, and fuel types; and (iv) energy efficiency potential.

(b) Each utility must disclose to the [insert relevant state agency], in a form prescribed by the [insert relevant state agency] (i) the amount and type of energy assistance and the number and type of households, if applicable, served by programs administered by the utility; (ii) the amount of money passed through to third parties that administer energy assistance programs; and (iii) subject to availability, any other information related to the utility's low-income assistance programs that is requested by the [insert relevant state agency].

(4)(a) In addition to the requirements under subsection (3) of this section, each electric utility must submit biennially to the [insert relevant state agency] an assessment of:

(i) The programs and mechanisms used by the utility to reduce energy burden and the effectiveness of those programs and mechanisms in both short-term and sustained energy burden reductions;

(ii) The outreach strategies used to encourage participation of eligible households, including consultation with community-based organizations and Indian tribes as appropriate, and comprehensive enrollment campaigns that are linguistically and culturally appropriate to the customers they serve in vulnerable populations; and

(iii) The funding levels needed to increase current levels of energy assistance by [XX] percent by 2030, and by [XX] percent by 2050.

(b) The assessment required in (a) of this subsection must include a plan to improve the effectiveness of the assessed mechanisms and strategies toward meeting the energy assistance need.

(5) A consumer-owned utility may enter into an agreement with a public university, community-based organization, or joint operating agency to aggregate the disclosures required in this section and submit the assessment required in subsections (3) and (4) of this section.

(6)(a) The [insert relevant state agency] must submit a biennial report to the legislature that: (i) aggregates information into a statewide summary of energy assistance programs, energy burden, and energy assistance need; (ii) identifies and quantifies current expenditures on low-income energy assistance; and (iii) evaluates the effectiveness of additional optimal mechanisms for energy assistance including, but not limited to, customer rates, a low-income specific discount, system benefits charges, and public and private funds.

(b) The [insert relevant state agency] must also assess mechanisms to prioritize energy assistance towards low-income households with a higher energy burden.

(7) Nothing in this section may be construed to restrict the rate-making authority of the Commission or the governing body of a consumer-owned utility as otherwise provided by law.

Section 12. Integration with Carbon and Electricity Markets Outside the State

(1) Within six months after the date of enactment, the Commission shall convene a stakeholder work group to examine the integration of actions taken pursuant to this act with carbon and electricity markets outside the state, and the compatibility of the requirements of this act with any existing or planned cap-and-trade programs.

(2) To assist in its examination of the issues identified in this section, as well as any other related issues, the Commission shall, at a minimum, invite the participation of representative electric utilities, gas companies, any federal power marketing agencies serving the state, and public interest and environmental organizations.

(3) Within two years after the date of enactment, the Commission shall adopt rules facilitating the integration of actions taken pursuant to this act with carbon and electricity markets outside the state, and enhancing the compatibility of the requirements of this act with any existing or planned cap-and-trade programs.

Section 13. Social Cost of Carbon

For the purposes of this act, the cost of greenhouse gas emissions resulting from the generation of electricity, including the effect of emissions, is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the two and one-half percent (2.5%) discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the U.S. government, August 2016. The Commission and other implementing agencies must adjust the costs established in this section to reflect the effect of inflation.

Section 14. Integrated Resource Planning

An electric utility's integrated resource plan shall, at a minimum, include:

(a) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;

(b) An assessment of commercially available, utility scale renewable and non-renewable generating technologies, including a comparison of the benefits and risks of purchasing power or building new resources;

(c) A comparative evaluation of renewable and non-renewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using “lowest reasonable cost” as a criterion;

(d) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage;

(e) An identification of an appropriate resource adequacy requirement consistent with prudent utility practice in implementing sections 3 through 5 of this act;

(f) An assessment, informed by the cumulative impact analysis conducted under section 15 of this act, of ways to increase the benefits and reduce the public health and environmental burdens on vulnerable populations and highly-impacted communities.

(g) A ten-year clean energy action plan for implementing sections 3 through 5 of this act at the lowest reasonable cost, including the specific actions to be taken by the utility consistent with its integrated resource plan. The clean energy action plan must be informed by the utility’s ten-year cost-effective conservation potential, and identify the potential cost-effective demand response and load management programs that may be required. It shall identify renewable resources, non-emitting electric generation, and distributed energy resources that may be required to meet the utility’s resource adequacy requirement; identify any need to develop new or expanded bulk transmission and distribution facilities; and estimate the extent to which the utility may need to rely on alternative compliance options under section 4(1)(b) of this act.

(3) An electric utility shall consider the social cost of carbon, as determined under section 13 of this act, when developing its integrated resource plan and clean energy plan. The social cost of greenhouse gas emissions must be incorporated when evaluating and selecting conservation policies, programs, and targets, and when evaluating and selecting medium and long-term resources options.

Section 15. Designation of Communities Highly Impacted by Fossil Fuel Pollution and Climate Change

Within one year of the date of enactment, the [insert state agency responsible for public health] shall designate, based on a cumulative impact analysis, communities within the state highly impacted by fossil fuel pollution and climate change.

Section 16. Severability

If any provision of this act or its application to any person or circumstance is held invalid, the remainder of the act or the application of the provision to other persons or circumstances is not affected.