HOUSE BILL 951: Modernize Energy Generation.

2021-2022 General Assembly

Committee:	Senate Rules and Operations of the Senate	**Date:**	July 23, 2021
Introduced by:	Reps. Arp, Szoka, D. Hall, Bell	**Prepared by:**	Jennifer McGinnis
Analysis of:	Third Edition		Staff Attorney

***OVERVIEW:** House Bill 951 would, among other things, do all of the following:*

- ***Require retirement of certain coal-fired generating facilities: the Allen Plant located in Gaston County, Marshall Units 1 and 2 located in Catawba County, the Roxboro Plant located in Person County, Cliffside Unit 5 located in Cleveland County, and the Mayo Plant located in Person County.***
- ***Assign designated replacement resources for each of the retiring coal-fired generating facilities.***
- ***Amend the program that required competitive procurement of renewable energy resources established under S.L. 2017-192/H589, to require an additional competitive procurement of energy and capacity from renewable energy facilities in the aggregate amount of 4,667MW megawatts alternating current (MW AC).***
- ***Require an electric public utility to use bond financing for $500,000,000 in certain energy transition costs related to retirement of units at the Allen Plant, Marshall Units 1 and 2, the Roxboro Plant, Cliffside Unit 5, and the Mayo Plant. This financing mechanism would not create any indebtedness for the State or any of its political subdivisions.***
- ***Authorize the electric public utilities operating in this State to jointly or separately incur costs up to an aggregate total of $50,000,000 to pursue an Early Site Permit (ESP) from the Nuclear Regulatory Commission for the siting of an advanced nuclear facility at a single location in the State. In addition, the bill would direct the electric public utilities to prepare and submit Subsequent License Renewal applications with the Nuclear Regulatory Commission for each of the six currently operating nuclear electric generating facility sites in the electric public utilities' balancing area authority.***
- ***Authorize "performance based regulation" of the electric public utilities operating in the State, meaning an alternative ratemaking approach that includes decoupling revenue from electricity consumption, one or more performance incentive mechanisms, and a multi-year rate plan, including an earnings sharing mechanism, or such other alternative regulatory mechanisms as may be proposed by an electric public utility.***
- ***Modify the existing "green source advantage" program, which is a renewable energy procurement program for large energy users, the military, and the University of North Carolina system.***
- ***Repeal the existing community solar program, and enact new "shared solar" and "community solar gardens" programs. Each program would require offering utilities to procure a certain amount of renewable energy (750 MW AC for the shared solar program and 60 MW AC from***

the community solar gardens program) to be made available for customers to purchase subscriptions for a certain amount of output of the renewable energy produced.

- ***Require offering utilities to file a "solar choice tariff" for approval by the Utilities Commission (Commission). The tariff would become the exclusive option available to customers that apply for net metering service (applicable to electric customers that (i) own a renewable energy facility for that person's own primary use or (ii) are customer generator lessees).***

- ***Direct the Commission to initiate a stakeholder process to provide interested parties the opportunity to formulate an agreement for a revised avoided cost methodology, and associated terms and conditions in order to modify certain existing power purchase agreements with small power producers.***
- ***Increase the maximum amount of total installed capacity of all solar energy facilities on an offering utility's system that are leased as authorized under the State's Distributed Resources Act from 1% to 5% of the previous five year average of the North Carolina retail contribution to the offering utility's coincident retail peak demand, an amount over which an offering utility may refuse to interconnect customers that would result in this limitation being exceeded.***
- ***Require customers installing solar or other behind the meter generation with a nameplate generation capacity over 100 kW that are participating in an offering utility's net metering tariff or solar choice tariff to have standby service, and set forth the basis on which the utility must calculate a standby service cost for such customers.***

BILL ANALYSIS/ CURRENT LAW:

PART I. CERTAIN REQUIREMENTS FOR GRID MODERNIZATION AND INVESTMENT IN CRITICAL ENERGY INFRASTRUCTURE

<u>Retirement of subcritical coal fired generating facilities and designated replacement resources</u>

Sections 1(b) through (f) of the bill would:
- Require retirement, by December 31, 2030, of "subcritical coal fired generating facilities" defined under the bill to mean the remaining units of the Allen Plant located in Gaston County, Marshall Units 1 and 2 located in Catawba County, the Roxboro Plant located in Person County, Cliffside Unit 5 located in Cleveland County, and the Mayo Plant located in Person County.
- Designate replacement resources to replace the capacity and energy lost by the retirement of the subcritical coal fired generating facilities.

With respect to the particular plants specified, the bill would require:
- **<u>Allen Plant</u>**: The remaining units of the Allen Plant must be retired on or before December 31, 2023. With respect to designated replacement resources for the site, the bill would require that, on or near the site of the Allen Plant, but in no event outside of Gaston County, the electric public utility must procure and own one or more energy storage systems (ESS) with a total capacity of approximately 20 MW AC / 80 megawatt hours ("MWh"). The utility would be required to exert reasonable efforts to ensure that the designated replacement resources are constructed according to a timeline that allows for retirement of the coal-fired generating

facility by the targeted retirement date, and the utility must provide updates to the Utilities Commission (Commission) regarding the status of such efforts in its integrated resource plans.

- **Marshall Units 1 and 2**: Marshall Units 1 and 2 must be retired on or before December 31, 2026. With respect to designated replacement resources for the site, the bill would require that, on or near the site of the Marshall Plant, but in no event outside of Catawba County, the electric public utility must procure and own designated replacement resources comprised of a natural gas fueled simple cycle combustion turbine generating facilities with a generating capacity totaling approximately 900 MW; provided that the electric public utility is authorized to propose a smaller combustion turbine generating facility where the utility determines that technological or other constraints so require. The utility would be required to exert reasonable efforts to ensure that the designated replacement resources are constructed according to a timeline that allows for retirement of the coal-fired generating facility by the targeted retirement date, and the utility must provide updates to the Utilities Commission regarding the status of such efforts in its integrated resource plans.
- **Roxboro Plant**: The applicable electric public utility would be required to file a coal retirement and replacement plan with the Commission on or before September 1, 2024. With respect to the designated replacement resource for the Roxboro Plant, the replacement resource must be a generating facility located on the Roxboro Plant site that satisfies all of the following criteria:
    - The resource has continuous generating and dispatch capabilities and other operating characteristics that provide system reliability benefits that are equal to or greater than the retiring Roxboro Plant.
    - The resource provides effective load carrying capability sufficient to ensure continued reliability of the system.
    - The resource has the ability to deliver continuous power at or near the maximum capacity of the resource for a continuous period of one week or longer without reliance on other grid resources.

  The bill provides, however, that in the event the applicable utility, in its reasonable discretion, determines that it will be unable or infeasible to procure or construct a generating facility at the Roxboro Plant site, it may site the replacement resource at another location in Person County, that satisfies these criteria.
- **Cliffside Unit 5**: The applicable electric public utility would be required to file a coal retirement and replacement plan with the Commission on or before September 1, 2027. With respect to designated replacement resources for the facility, the replacement resource must be an ESS to be procured and owned by the utility. The utility must seek to locate a substantial portion of the ESS on the Cliffside Unit 5 site, but may site such ESS on or near other utility property where such siting will provide increased benefit to customers.
- **Mayo Plant**: The applicable electric public utility would be required to file a coal retirement and replacement plan with the Commission on or before September 1, 2027. With respect to designated replacement resources for these facilities, the replacement resource for each facility shall be an ESS to be procured and owned by the utility. The utility must seek to locate a substantial portion of the ESS on the Mayo site, but may site such ESS on or near other utility property where such siting will provide increased benefit to customers.

These sections of the bill would also:

- Set forth a process for filing of coal retirement and replacement plans, and approval thereof by the Commission.
- Provide that notwithstanding any date established for retirement a subcritical coal-fired generating facility, in the event the utility determines that the retirement of any such facility would have the potential to compromise reliability of the utility's service, or otherwise impact the ability of the utility to comply with any applicable reliability requirements, the utility must file notice with the Commission describing the reliability issues preventing compliance with the specified retirement date, and requesting a delay of the retirement date. Upon receipt of a notice and request for retirement delay, the Commission may conduct a hearing regarding such delay, and must issue an order approving or rejecting the request for delay within 90 days of receipt of such notice and request.
- Prohibit the retirement of any subcritical coal-fired generating facilities until the applicable designated replacement resource has been placed in-service; provided, however, the utility would be authorized to retire the subcritical coal-fired generating facility prior to the in-service date of the applicable designated replacement resource if the utility determines that it will be able to maintain reliable service in that circumstance.
- Authorize a utility to:
  - Establish a regulatory asset for the remaining net book value of each subcritical coal-fired generating facility retired, and amortize the regulatory asset at the same rate the subcritical coal-fired generating facility was previously being depreciated; and
  - Include the regulatory asset in rate base for ratemaking purposes. In a future general rate proceeding, the Commission must establish an amortization period for recovery and allow a return on the unamortized balance.
- Require that with respect to designated replacement resources, renewable generating facilities and ESS required to be procured must utilize competitive procurement for the design, engineering, and construction of such generating facilities and ESS.
- Authorize a utility to recover from its customers the reasonably and prudently incurred cost of all generation facilities and ESS purchased or constructed as required by the bill.

Competitive procurement of renewable energy resources

Section 1(g) of the bill would amend the program that required competitive procurement of renewable energy resources established under S.L. 2017-192/H589. This program required electric public utilities with more than 150,000 customers (Duke Energy Carolinas and Duke Energy Progress) to issue a request for proposals for a total procurement of 2,660 MW of capacity from renewable energy facilities over a 45-month term.

The bill would require an additional competitive procurement of energy and capacity from renewable energy facilities in the aggregate amount of 4,667 MW AC from 2021 through 2026 (approximately 777 MW AC per year). Provided, however, the total amount of energy in the competitive procurement would be adjusted up or down by any amount in which the public utility's renewable energy procurement outside of the competitive procurement, the green source advantage, and the shared solar programs (described further in this summary) is more or less than 3,500 MW AC.

In addition, the bill would modify a provision enacted under H589 (2017), which authorized the Commission to, upon termination of the initial competitive procurement period, require additional procurement of new renewable energy resources, with the amount to be procured to be determined by the Commission, based on a showing of need evidenced by the electric public utility's most recent biennial integrated resource plan. The bill would delete the language concerning a showing of need, and in lieu, require the Commission to determine: (i) whether it is in the interest of ratepayers to require further competitive procurement of renewable generating facilities by the electric public utilities; (ii) the amount to be procured, and (iii) the allocation of ownership between third parties and electric public utilities. The Commission's determination must still be based on the electric public utility's most recent biennial integrated resource plan or annual update accepted or approved by the Commission, provided that such plan assures adequate, reliable utility service.

Newly required procurements occurring after January 1, 2021 would be subject to the following ownership requirements:

- 45% of the total MW AC of renewable energy facilities to be procured must be supplied through the purchase of renewable energy, capacity, and environmental and renewable attributes from renewable energy facilities owned and operated by third parties that commit to allow the procuring electric public utility rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources. Facilities owned and operated by third parties would be subject to a cap on facility nameplate capacity of 80 MW AC or less for each facility.
- 55% of the total MW AC of renewable energy facilities to be procured must be supplied from renewable energy facilities to be acquired or otherwise sourced from third parties and owned and operated by the soliciting electric public utility.

For procurements occurring after January 1, 2021, the bill would prohibit the electric public utilities and their affiliates from submitting bids into the competitive procurement process or to have any financial interest in third party bidders.

The bill provides that the price to be paid under any power purchase agreements for third-party owned resources, combined with the cost of any necessary transmission or distribution upgrade, would be capped by the utility's current forecast of its avoided cost calculated over the term of the power purchase agreement. The public utility's current forecast of its avoided cost must be consistent with the Commission-approved avoided cost methodology.

A utility would be authorized to recover from its customers the reasonably and prudently incurred costs paid under executed power purchase agreements through an annual rider approved by the Commission and reviewed annually; provided, however, costs that may be recovered by the utility for utility-owned renewable generating facilities would be subject to the same cost caps applicable to third-party owned resources.

Authorize financing of certain energy transition costs

Section 2 of the bill would require an electric public utility to use bond financing for certain energy transition costs related to retirement of Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant. Specifically, "energy transition costs," as specified by the bill are:

- A cost other than a monetary penalty, fine, or forfeiture assessed against a public utility by a government agency or court under a federal or State environmental statute, rule, or regulation, for retirement of Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant. The total amount that must be securitized is $500,000,000, which must be allocated among these plants in a manner that realizes the greatest cost savings to ratepayers as determined by the Commission. Such costs include:

- An amount determined and approved by the Commission not to exceed the total aggregate unrecovered net book value of the subcritical coal fired electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant.
- The following costs the public utility has incurred or will incur caused by, associated with, or that remain as a result of the early retirement of electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant. Such costs include:
  - All incremental costs, including capital costs, appropriate for recovery from existing and future retail customers receiving transmission or distribution service from the electric public utility that the utility has incurred or expects to incur as a result of the early retirement of these plants, including the costs of decommissioning and restoring the site of such early retired electric generating facilities, except for costs incurred pursuant to G.S. 130A-309.200 to G.S. 130A-309.226[1] or 40 C.F.R. Subpart D[2], , which are not subject to this section.
  - The electric public utility's cost of capital from the date this section becomes effective to the date the energy transition bonds are issued, calculated using the public utility's weighted average cost of capital as defined in its most recent base rate case proceeding before the Commission net of applicable income tax savings related to the interest component. Such costs also include other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.

This financing mechanism is similar to that authorized by the General Assembly for storm recovery costs in 2019. This financing mechanism would not create any indebtedness for the State or any of its political subdivisions. Bonds issued would be secured through a dedicated energy transition charge that is separate and distinct from the utility's base rate.

There are three major components of utility cost recovery charge securitization:

- State legislation.
- A financing order.
- A true-up mechanism.

State Legislation

[1] State requirements for coal ash management.

[2] Federal requirements for management of hazardous waste.

The legislation creates an energy transition charge and provides that the revenues generated by this charge, known as energy transition property, is a property right that can be transferred and pledged as security for the energy transition bonds. Since this property right may not be governed by the Uniform Commercial Code (UCC), the legislation establishes the procedures for creating, perfecting, and enforcing the security interest in energy transition property.

This property right is created through the political and regulatory process; to ensure the credibility of the energy transition bonds, the legislation includes a State non-impairment obligation. Once energy transition bonds are issued, the State and its agencies, including the Commission, agrees not to take any action that would limit or alter the energy transition charges (which is the property right securing the bonds) until the energy transition bonds have been paid and performed in full.

The legislation protects bondholders in several additional ways:

- It provides that the sale of an interest in energy transition property is a true sale and that ownership passes to the party characterized as the purchaser. The purchaser may be a limited purpose subsidiary of the public utility created for the sole purpose of issuing the energy transition bonds. This provision protects bondholders from the interruption or impairment of cash flows in the event of a utility bankruptcy.
- It provides that the interest in the energy transition property is not affected or impaired by the commingling of energy transition charges with other amounts.
- It provides that the energy transition charge must be imposed on all customer bills collected by the public utility or its successors or assignees. The charge must be stated as a separate, itemized charge on customer bills that is separate and apart from the public utility's base rate.
- It provides that the energy transition charge must be paid by all existing or future retail customers receiving transmission or distribution service form the public utility, even if a customer elects to purchase electricity from an alternative electricity supplier (nonbypassablility).

Financing Order

The legislation requires the applicable electric power utility to petition the Commission for a financing order for energy transition costs, and establishes the process for a petition. Again, per the definition of "energy transition costs" in the bill, this includes the unrecovered net book value of early retired electric generating facilities at Marshall Units 1 and 2, the Allen Plant, the Roxboro Plant, the Cliffside Unit 5 Plant, and the Mayo Plant, as well as certain costs the utility has incurred or will incur caused by, associated with, or that remain as a result of the early retirement of electric generating facilities at these plants. The total amount that must be securitized is $500,000,000, which must be allocated among these plants in a manner that realizes the greatest cost savings to ratepayers as determined by the Commission.

A petition must include energy transition costs incurred by the utility and an estimate of the costs that are being undertaken but are not completed, an indicator of the amount of energy transition costs to be financed using energy transition bonds, an estimate of the financing costs related to the bonds, an estimate of the energy transition charges necessary to recover energy transition costs, and a comparison between the net present value of the cost to customers estimated to result from the issuance of energy bonds and the cost that would result from the application of the traditional method of financing and recovering energy transition costs; this comparison must demonstrate that issuance of energy transition bonds and the imposition of energy transition charges are expected to provide quantifiable benefits to customers.

Before granting a financing order, the Commission must find that the issuance of the energy transition bonds and the imposition of energy transition charges are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of energy transition bonds.

The financing order sets forth specific transaction terms and related provisions, including the amount of energy transition costs to be financed using energy transition bonds, the imposition and collection of energy transition charges that are nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service from the public utility or its successors or assignees, the maturity period of the bonds, a formula-based true-up mechanism, the creation of energy transition property that will be used to secure the bonds, and a method of tracing funds collected as energy transition charges. The financing order is irrevocable.

True-Up Mechanism

The legislation specifies that the financing order must include a requirement that the public utility file with the Commission at least annually a petition or letter applying the formula-based mechanism, and request adjustments in the energy transition charge, if necessary, to a sufficient level to ensure the bond payment obligations. The Commission does not have the discretion to disapprove or alter the true-up calculation, except to correct mathematical and clerical errors. The adjustment of the energy transition charge through this mechanism is the most significant credit component of these transactions.

Advanced nuclear early site permit and subsequent license renewal

Section 3.(a) of the bill would allow the electric public utilities operating in the State to jointly or separately incur costs up to an aggregate total of $50,000,000 to pursue an Early Site Permit (ESP) from the Nuclear Regulatory Commission (NRC) Commission for siting of an advanced nuclear facility at a single location in the State. The utilities would be required to make reasonable efforts to obtain and use any federal funding available to offset the costs. Each participating utility would be authorized to establish a regulatory asset and defer incremental and carrying costs to that regulatory asset until the costs can be reflected in customer rates. The Commission would be directed to establish an amortization period for recovery, and allow a return on the unamortized balance.

Section 3.(b) would direct the electric public utilities to prepare and submit Subsequent License Renewal applications with the NRC for the six currently operating nuclear electric generating facility sites in the utilities' balancing area authority, and report on the status of the applications in their integrated resource plan filings.

PART II. RATEMAKING MODERNIZATION/AUTHORIZE PERFORMANCE BASED REGULATION OF ELECTRIC PUBLIC UTILITIES

Section 4 of the bill would provide that notwithstanding the methods for fixing rates established under general ratemaking statute (G.S. 62-133), upon application of an electric public utility, the Commission could authorize "performance based regulation" or "PBR," which means an alternative ratemaking approach that includes decoupling[3], one or more performance incentive mechanisms[4], and a multi-year rate plan (MYRP)[5], including an earnings sharing mechanism[6], or such other alternative regulatory mechanisms as may be proposed by an electric public utility. Any PBR application approved could remain in effect for a plan period of not more than 36 months. With regard to Commission consideration of a PBR application:

- The Commission may approve a PBR application by an electric public utility only upon a finding that a proposed PBR would result in just and reasonable rates, is in the public interest, and is consistent with criteria otherwise established in the bill or rules adopted thereunder.
- The Commission must conduct a hearing on a PBR application.
- After hearing, the Commission must issue an order approving or rejecting the electric public utility's PBR application. The Commission would not be permitted to modify the PBR application.
- In reviewing any such PBR application under this section, the Commission must consider whether the PBR application:
  - Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer.
  - Reasonably assures the continuation of safe and reliable electric service.
  - Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.
- The Commission may also consider whether the PBR application:
  - Encourages peak load reduction or efficient use of the system.
  - Encourages utility-scale renewable energy and storage.
  - Encourages distributed energy resources.
  - Reduces low-income energy burdens.
  - Encourages energy efficiency.
  - Encourages carbon reductions.
  - Encourages beneficial electrification, including electric vehicles.
  - Supports equity in contracting.
  - Promotes resilience and security of the electric grid.
  - Maintains adequate levels of reliability and customer service.
  - Promotes rate designs that yield peak load reduction or beneficial load-shaping.

The following would apply to a MYRP:

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[3] "Decoupling ratemaking mechanism" means a ratemaking mechanism intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis by its residential customers.

[4] "Performance incentive mechanism" or "PIM" means a ratemaking mechanism that links electric public utility revenue or earnings to electric public utility performance in targeted areas consistent with policy goals, as that term is defined by this section, approved by the Commission, and includes specific performance metrics and targets against which electric public utility performance is measured.

[5] "Multi-year rate plan" or "MYRP" means a ratemaking mechanism under which the Commission sets base rates for a multi-year period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application pursuant to G.S. 62-133, along with an earnings sharing mechanism.

[6] "Earnings sharing mechanism" means an annual ratemaking mechanism that shares surplus earnings between the electric public utility and customers over the period of time covered by a MYRP.

- The base rates for the first rate year of a MYRP must be fixed in the manner prescribed under the general ratemaking statute, including actual changes in costs, revenues or the cost of the electric public utility's property used and useful, or to be used and useful within a reasonable time after the test period, plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.
- Subsequent changes in base rates in the second and third rate years of the MYRP must be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period.
- The amount of increase in the second and third rate years under the MYRP may not exceed 4% of the electric public utility's North Carolina retail jurisdictional revenue requirement that is used to fix rates during the first year of the MYRP, excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year.
- The revenue requirements associated with any single new generation plant placed in service during the MYRP for which the total plant in service balance exceeds $500 million may not be included in a MYRP. Instead, the utility may request and the Commission may grant, if it deems appropriate, permission to establish a regulatory asset and defer to such regulatory asset incremental costs related to such electric generation investments to be considered for recovery in a future rate proceeding.
- In setting the electric public utility's authorized rate of return on equity for a MYRP period, the Commission shall consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.
- In a proceeding authorizing a MYRP, the Commission must establish a rider to refund amounts related to the earnings sharing mechanism, and to refund or collect amounts related to PIM rewards or penalties, and decoupling adjustments.
- Within 60 days of the conclusion of each rate year, the Commission must establish a proceeding to:
    - Examine the earnings of the electric public utility during the rate year to determine if the earnings exceeded the authorized rate of return on equity determined by the Commission in the proceeding establishing the PBR. If the weather normalized earnings exceed the authorized rate of return on equity plus 50 basis points, the excess earnings above the authorized rate of return on equity plus 50 basis points will be refunded to customers in the rider established by the Commission. If the weather normalized earnings fall below the authorized rate of return on equity, the electric public utility may file a rate case pursuant to G.S. 62-133.
    - Evaluate the performance of the electric public utility with respect to Commission-approved PIMs applicable in the rate year. Any financial rewards must be collected from customers and any penalties refunded to customers, in each case, through the rider established by the Commission.
    - Evaluate the decoupling ratemaking mechanism, and refund or collect, as applicable, a corresponding amount from residential customers through the rider established by the Commission.

Requirements applicable to PIMs:

- PIMs proposed by an electric public utility must include one or more of the following:
  - Rewards based on the sharing of savings achieved by meeting or exceeding a specific policy goal.
  - Rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet a specific policy goal, which shall not be greater than 25 basis points.
  - Fixed financial rewards to encourage achievement of specific policy goals, or fixed financial penalties for failure to achieve policy goals.
- The policy goal targeted by a PIM must be clearly defined, measurable with a defined performance metric, and solely or primarily within the electric public utility's control.
- Any PIM must be structured to ensure that any penalty would be refunded to customers and any reward would be collected from customers and must be limited such that the total of all potential and actual PIM incentives or penalties does not exceed 1.0% of the electric public utility's total annual revenue requirement that is used to fix rates during the first year of the MYRP, excluding any revenue requirement for the capital spending projects to be placed in service during the first rate year, where the PIM is approved.

At any time prior to expiration of a PBR plan period, the Commission, with good cause and upon its own motion or petition by the Public Staff, may examine the reasonableness of an electric public utility's rates under a plan, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust base rates or PIMs as necessary.

The Commission would be required to adopt rules to implement the requirements of the section no later than 120 days after the date this section becomes law.

This section would be effective when it becomes law and apply to any ratemaking mechanisms filed by an electric public utility on or after the date that rules adopted by the Commission, as required by this section, become effective.

PART III. CUSTOMER RENEWABLES PROGRAMS

Green Source Advantage

House Bill 589 (2017) enacted the Green Source Rider program, which is a renewable energy procurement program for large energy users, the military, and the University of North Carolina (UNC) system. Large energy users are defined as those with a contract demand for 1 MW or more, or 5 MWs or more at multiple service locations when combined in aggregate. The program must be offered by the electric public utilities for a period of five years or until December 31, 2022, whichever is later, and must not exceed a combined 600 MW AC of total capacity.

Section 5 of the bill would amend the Green Source Rider program enacted by House Bill 589 (2017) by, among other things, doing the following:

- Establish additional conditions that would be applicable to participating customers who have not entered into an agreement under the Green Source Rider program on or before January 1, 2021.

- Direct the public utilities to establish reasonable credit requirements for financial assurance for renewable energy suppliers (in addition to existing requirements for eligible customers).
- Provide that if customer interest in this program exceeds the specified program capacity limits, the Commission may expand the program. In the event the Commission expands the program, the total amount of renewable energy resources to be competitively procured pursuant to G.S. 62-110.8 must be reduced by an amount totaling the additional program capacity authorized by the Commission.
- Extend the period that that major military installations and UNC have to fully subscribe to all their allocations from December 31, 2020, to December 31, 2022.
- Modifies the bill credit that a program customer would receive for those customers who enter into an agreement after the effective date of this section to allow the customer to choose between two bill credit options:
  - A bill credit equal to the hourly real time avoided cost or day ahead avoided cost.
  - A bill credit equal to avoided cost as determined in a manner consistent with the most recent Commission-approved methodology for a period of two, five or ten years, as selected by the customer.
- Establish the following conditions under which major military installations and UNC may alternatively participate in the program:
  - On or before December 31, 2021, UNC may request up to 250 MW AC of renewable energy capacity, and major military installations may request up to 100 MW AC of renewable energy capacity. Any unclaimed capacity from the amounts authorized must be reallocated for participation by any other eligible customer.
  - Upon receipt of written notice, the electric public utility must competitively procure from independent third parties renewable energy and capacity from one or more renewable energy facilities to provide the total requested amount of renewable energy capacity using the competitive procurement process set forth in G.S. 62-110.8 for procurements occurring on or after January 1, 2022.
  - In addition to their normal retail bill, the major military installations and The University of North Carolina must pay a product charge equal to the price established through the competitive procurement for the renewable energy facility or facilities procured for them, respectively. The electric public utility must pay the owner of the renewable energy facility or facilities at the price established through the competitive procurement. The major military installations and The University of North Carolina would then be entitled to a bill credit equal to the price established through the competitive procurement for the renewable energy facility or facilities procured for them, respectively.

Shared Renewables/Community Solar Gardens

Section 6(a) would amend or define several terms in the State's Distributed Resources Act.

Section 6(b) would require electric public utilities to complete a competitive procurement seeking new renewable resources totaling 750 MW AC over a period of approximately three years, which would be made available for customers to purchase subscriptions for a certain amount of output of the renewable energy procured. If customer interest in this program exceeds 750 MW AC, however, the Commission may expand the program. In the event the Commission expands the program, the total amount of renewable energy resources to be competitively procured pursuant to G.S. 62-110.8 would be reduced by an amount totaling the additional program capacity authorized by the Commission.

The program would be subject to the following key criteria:

- Large and small commercial and industrial customers would receive 70% of total program volume, government customers would receive 20%, and residential customers would receive 10%. Unsubscribed portions will be made available to all eligible classes during a second enrollment period and, if oversubscribed during that second enrollment period, through a random selection process and then first come, first serve.
- Each participating customer must:
  - Pay a product charge equal to the average contract price for all facilities with which the offering utility has contracted in a particular procurement cycle pursuant to the applicable competitive solicitation.
  - Pay a reasonable administration fee approved by the Commission in order for the offering utility to recover the administrative costs of the program.
  - Receive a bill credit equal to the product charge for such customer.
- Once a subscription has been awarded, it must remain in place until the earlier of the following:
  - The customer terminates their subscription.
  - The customer cancels their retail service.
  - Twenty years after the renewable generating facility to which such customer has been subscribed achieved commercial operation.

Section 6(c) of the bill would repeal the community solar energy facility program enacted in House Bill 589 (2017), to be replaced with the community solar gardens program enacted in Section 6.(d) of this act.

Section 6(d) of the bill would enact a new community solar gardens program, requiring electric public utilities serving more than 150,000 North Carolina retail jurisdictional customers, either jointly or separately, to complete a competitive procurement of up to 50 MW of new distribution-connected solar generation which would be made available for customers to purchase subscriptions for a certain amount of output of the renewable energy procured. Electric public utilities serving between 100,000 and 150,000 retail jurisdictional customers would be allowed, but not required, to complete a competitive procurement of up to 10 MW of new distribution-connected solar generation.

Program highlights include:

- Small commercial and industrial customers would receive 35% of total program volume, government customers would receive 30%, and residential customers would receive 35%.
- Subscribers would receive a bill credit at their pro rata share of the offering utility's monthly levelized revenue requirement for each facility within its community solar gardens program.
- Once a subscription has been awarded, it must remain in place until the earlier of the following:

- o The customer terminates their subscription.
- o The customer cancels their retail service.
- o Twenty years after the solar generating facility to which such customer has been subscribed achieved commercial operation.

- The recoverable capital costs for constructing community solar gardens facilities may not exceed $1.90 per watt, inclusive of interconnection costs. Projects whose expense falls below this cost cap and is otherwise in accordance with the terms of this section will be deemed consistent with the public convenience and necessity. Each offering utility would be permitted to establish a regulatory asset and defer to such regulatory asset the incremental costs of all solar generating facilities procured or built under this section until such time as the costs can be reflected in customer rates.
- The offering public utilities would be required to try to procure at least 25% of total procurement for community solar garden facilities that are capable of being placed into service before January 1, 2024.

Solar Choice Tariff

Section 7 would:

- o Repeal a requirement enacted in House Bill 589 (2017) that required the Commission to establish net metering rates for electric customers that (i) own a renewable energy facility for that person's own primary use or (ii) are customer generator lessees.
- o Enact a requirement that each offering utility[7] file for Commission approval a solar choice tariff that would become the exclusive option available to customers that apply for net metering service after Commission approval pursuant to this section. The Commission would be required to approve an offering utility's application to establish a solar choice tariff that meets all of the following objectives:
  - o Provides for monthly netting with net exports credited at Commission-approved avoided cost in light of the costs and benefits of the solar choice tariff achieving the objectives of a net metering program.
  - o Provides for monthly netting within each pricing period for time-variant and dynamic pricing structures with net exports credited at Commission approved avoided cost.
  - o Provides rate design options that align the customer generator's ability to achieve bill savings with long-term reductions in the overall cost the offering utility will incur in providing electric service, including, but not limited to, time-variant and dynamic pricing structures.
  - o Reduces cross-subsidization by non-participants through mechanisms that allow offering utilities the opportunity to recover customer costs and distribution costs, including a minimum monthly bill, grid access fee for oversized systems, and non-bypassable charges to recover storm recovery, cybersecurity, and public purpose charges for ratepayer funded programs like energy efficiency, demand side management, and resiliency. Such recovery mechanisms must not, however, include a standby charge where billing is based on the capacity of the renewable energy system.

[7] For purposes of this section, an "offering utility" includes all electric public utilities serving more than 100,000 retail electric customer in the State as of January 1, 2021.

- Minimizes, to the greatest extent practicable, any intra-class cross-subsidization identified using the offering utility's most recently approved embedded cost of service study.
- Encourages customer adoption of other energy savings, demand reduction, or grid services technologies and participation in cost-effective programs that can be offered in conjunction with a solar choice tariff to help lower the cost of providing service and maximize grid benefits.

Customer generators taking service under a pre-existing net metering tariff prior to Commission approval of a solar choice tariff would be given the option to transition to the new solar choice tariff or continue to take service under the offering utility's pre-existing net metering tariff in effect at the time of interconnection of that customer generator's net metering facility until January 1, 2040. After January 1, 2027, a non-by passable charge based upon the DC capacity of the facility would be added for customers who remain on a pre-existing net metering tariff. Provided, however, customers participating in a retail demand electric tariff in effect on or before July 1, 2021, or a customer who elects to take service under such retail demand tariff, would be exempt, however, from other cost recovery provisions of this section.

The solar choice tariff required to be filed with the Commission must be filed by each offering utility no later than 120 days after the effective date of this section, and the Commission must issue an order to approve, modify, or deny the program no later than 90 days after the submission of the program by the utility.

- Increase the maximum amount of total installed capacity of all solar energy facilities on an offering utility's system that are leased as authorized under the State's Distributed Resources Act from 1% to 5% of the previous five year average of the North Carolina retail contribution to the offering utility's coincident retail peak demand, an amount over which an offering utility may refuse to interconnect customers that would result in this limitation being exceeded.
- Modify the definition of the term "energy efficiency measure" under the State's Renewable Energy Portfolio Standard statutes.
- Require customers installing solar or other behind the meter generation with a nameplate generation capacity over 100 kW that are participating in an offering utility's net metering tariff or solar choice tariff to have standby service. Provided, however, customers participating in a retail demand electric tariff in effect on or before July 1, 2021, or a customer who elects to take service under such retail demand tariff, would be exempt from the standby charge.

Potential modification of certain existing power purchase agreements with small power producers

Section 8 of the bill would require the Commission to initiate a stakeholder process (including the Public Staff, electric public utilities, and small power producers) to provide interested parties the opportunity to establish the rates to be paid by the electric public utilities in connection with the modification of certain existing power purchase agreements of certain small power producers[8] to present to the Commission that would accomplish both of the following:

- Provide small power producers a one-time option to elect, within 180 days of a Commission order authorizing such action, to amend their existing power purchase agreement, extending into a new longer term power purchase agreement for a term equal to the remaining term of the existing power purchase agreement plus an additional 10 years, notwithstanding contract term limits prescribed in G.S. 62-156(c);
- Establish capacity and energy rates to be paid by the electric public utilities that are designed to take into consideration the currently contracted capacity and energy rates, capacity and energy rates to be computed at the time the small power producer elects to exercise the option to amend their existing power purchase agreement. In developing these rates, stakeholders must consider whether use of the developed rates, for purchases from small power producers for an extended future term, are just and reasonable to the electric consumer of the electric utility, and in the public interest.

Within 180 days of the Commission's initiation of the stakeholder process, the stakeholders must present, jointly or separately, their recommendations to the Commission. The Commission must approve the proposed rates and resulting amended power purchase agreements if the Commission finds that the proposed methodology: (i) reduces costs to customers in the short term and over the life of the amended power purchase agreement, evaluated from the date of the amendment through to the end of the amended agreement; (ii) fairly compensates small power producers that elect such treatment; and (iii) is just and

Section 8.1 of the bill would prohibit executive branch action with respect to the State's participation in Regional Greenhouse Gas Initiative[9] (RGGI), and implementation of emissions limitations and cap and trade requirements attendant with the RGGI program, until such time as the General Assembly enacts legislation to authorize such actions.

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EFFECTIVE DATE: Except as otherwise provided, the bill would be effective when it becomes law.

Chris Saunders, Kyle Evans, Aaron McGlothlin, Trina Griffin, and Cindy Avrette, staff attorneys with the Legislative Analysis Division, substantially contributed to this summary.

[8] "Small power producers" for the purpose of the section are those generating solar electricity with a total capacity equal to or less than five MW AC that established a legally enforceable obligation in accordance with the Commission's then applicable requirements on or before November 15, 2016 and have entered into a long-term contract exceeding two years to sell their full output to the interconnected electric public utility under Section 210 of the Public Utility Regulatory Policies Act of 1978.

[9] The Regional Greenhouse Gas Initiative (RGGI) is a regional, "market-based" carbon dioxide (CO_2) emissions reduction program among certain states to cap and reduce CO_2 emissions from the fossil fuel-fired electric power generators located within those states. Under the program, fossil fuel-fired electric power generators with a capacity of 25 megawatts MW or greater located in signatory states are required to obtain allowances to offset their CO_2 emissions.