HB 755-FN - AS INTRODUCED

2025 SESSION

25-0871
05/08

HOUSE BILL ***755-FN***

AN ACT relative to the state's electric utility market.

SPONSORS: Rep. McGhee, Hills. 35; Rep. Caplan, Merr. 8; Rep. Cormen, Graf. 15; Sen. Watters, Dist 4

COMMITTEE: Science, Technology and Energy

ANALYSIS

This bill revises the definition of grid modernization to reference cost-effective measures intended to create a competitive market place of electricity suppliers, defines "load reducer" for purposes of electric utility restructuring; and establishes certain retail market reforms intended to enable innovation.

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Explanation: Matter added to current law appears in ***bold italics.***
Matter removed from current law appears [~~in brackets and struckthrough.~~]
Matter which is either (a) all new or (b) repealed and reenacted appears in regular type.

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STATE OF NEW HAMPSHIRE

In the Year of Our Lord Two Thousand Twenty Five

AN ACT relative to the state's electric utility market.

Be it Enacted by the Senate and House of Representatives in General Court convened:

1 Legislative Findings and Purpose.

I. It has been the policy of the state of New Hampshire since the 1996 enactment of RSA 374-F, the Electric Utility Restructuring Act, the 2010 passage of RSA 362-A:9, the net metering law, the 2013 passage of RSA 374-G, the Electric Utility Investment in Distributed Energy Resources Act, and the 2019 passage of RSA 53-E, the Community Power Aggregation Act, that:

(a) Electricity suppliers should be able to compete to provide wholesale and retail services, including by setting their own terms, conditions, and rates, including those for distributed energy resources (DERs);

(b) DERs may be used strategically to lower transmission and distribution grid costs; and

(c) The promotion of net metering and distributed generation generally should be pursued in a competitive environment pursuant to the restructuring policy principles set forth in RSA 374-F:3.

II. Implementation of these competitive market policy goals has still largely not occurred, requiring reforms to the New Hampshire retail market. Currently, suppliers serving residential and small to mid-sized non-residential customers do not have the practical ability to offer time varying rates for energy usage or rates for exported energy, such as with net metering, in the same way that New Hampshire utilities are able, leaving those consumers wanting such choices with only one option, extending the use of monopoly services. Customer choice through the competitive market for all but the largest non-residential customers has been limited to commodity service for consumption only at flat rates that do not reflect the value of when electricity is consumed or produced.

III. The absence of a freely competitive market has necessitated the state’s continued reliance on the commission to regulate the pace and extent of retail innovations, which are largely limited to customer programs, utility net metering tariffs, and distribution interconnected DER projects proposed by the electric distribution utilities. The public interest would be better served by allowing competitive entities to engage in permissionless innovation, by privately investing in DERs to support wholesale and retail energy markets along with providing distribution grid services that lower retail customer costs, with compensation based on actual performance and value produced instead of requiring cost recovery from ratepayers through distribution and other non-bypassable charges.

IV. The general court understands that utilities are functionally responsible for enabling retail market competition. The first annual report requested by the general court of the grid modernization advisory group (GMAG) established pursuant to RSA 12-P:6, explained that ongoing utility investments in digital systems and software are designed to "form the backbone for communication of price signals, accurate measurement of energy consumption and production, and enabling energy arbitrage" and that all such systems would function together to "enhance grid efficiency, support the cost-effective integration of DERs, [and] enable a competitive market where suppliers and aggregators can intermediate price signals to empower consumers with dynamic pricing and energy management capabilities."

V. This chapter enables the competitive market that New Hampshire policy calls for by providing timely and clear direction to the commission, department of energy, and electric distribution utilities to increase value and lower costs for NH residents and businesses. This chapter enables competitive forces and greater customer choice and autonomy by providing solutions to current limitations around data interchange, customer billing, retail transmission pricing, retail metering, and wholesale load and settlement services. Together these reforms will enable suppliers to offer innovative rates and services including time varying rates and net metering on a competitive basis to drive more optimal private investment in, and intelligent management of, onsite and community scale generation, battery storage, electric vehicles, and flexible loads. This framework will allow suppliers to monetize the value of such local resources through: (i) participation in ISO-NE wholesale markets; or alternatively; (ii) participation in local energy markets as load reducers that decrease wholesale energy, capacity, and transmission charges, while (iii) potentially also providing distribution grid support services to electric distribution utilities. Battery storage systems will also have the option of operating as load reducers while providing critical reliability services to ISO-NE as regulation resources.

2 Electric Utility Restructuring; Definitions. Amend the introductory paragraph of RSA 374-F:2, XI to read as follows:

XI. "Grid modernization" means improvements to electric distribution or transmission infrastructure, including related data analytics equipment, that are designed to accommodate or facilitate the ***cost-effective*** integration of ***DERs and*** renewable electric generation resources with the electric distribution grid***,*** [~~or~~] ***allow accurate measurement of energy consumption and production, convey price signals, enable a competitive market where electricity suppliers can intermediate price signals to empower consumers with time varying and dynamic pricing and energy management capabilities, and*** to otherwise enhance electric distribution or transmission grid reliability, grid security, demand response capability, customer service or energy efficiency, or conservation and includes:

3 New Paragraphs; Electric Utility Restructuring; Definitions. Amend RSA 374-F:2 by inserting after paragraph XII the following new paragraphs:

XIII. "Load reducer" means the term as used by ISO-NE, which recognizes that the output from distributed energy resources should be excluded from monthly regional network load, LSE load and coincident peak contributions for purposes of determining transmission, wholesale energy, and capacity charges, respectively, provided that each such resource:

(a) Has a maximum rated export capacity at the point of interconnection with the distribution grid of less than 5 megawatts;

(b) Is not registered with ISO-NE as a generator asset, or is registered only to participate as an alternative technology resource (ATRR); and

(c) Is not otherwise participating in any FERC jurisdictional wholesale electricity markets except as an ATRR.

XIV. The terms "assigned meter reader", "coincident peak contributions," "designated agent," "load," "load asset," "generator asset," "host utility", "load obligation," "load serving entity (LSE)," "monthly regional network load," and "regional network service (RNS)" shall have the meanings used by ISO New England, Inc. (ISO-NE).

4 New Section; Electric Utility Restructuring; Retail Market Reforms. Amend RSA 374-F by inserting after section 4 the following new section:

374-F:4-a Retail Market Reforms to Enable Innovation.

I. Implementation of Retail Metering and Utility Settlement Process Changes to Enable Voluntary Wholesale Market Participation. Pursuant to the relevant ISO-NE tariffs and procedures that take effect on November 1, 2026, the commission, department of energy, and electric distribution utilities shall enable distributed energy resource aggregators to own and install revenue meters and to serve as the assigned meter reader for distributed energy resources, as these terms are defined by ISO-NE for purposes of this paragraph, for their participation in ISO-NE wholesale markets. Such unbundling of retail metering requires that electric distribution utilities, as the host utility responsible for provision of metered and estimated data to ISO-NE for their respective metering domains, ensure that each such distributed energy resource's metered net import or export of energy to the distribution grid is not inadvertently included and double-counted in other generator or load assets, as applicable. The commission, through orders issued or tariffs approved in adjudicated proceedings, shall authorize customers in each utility territory to participate in such distributed energy resource aggregations, and shall approve a standard coordination agreement governing the relationship between all electric distribution utilities and such distributed energy resource aggregators and providing for customer data confidentiality.

II. Authorization of Comparable Interval Metering Options for DERs as Load Reducers. Prior to November 1, 2026, the commission and electric distribution utilities shall either:

(a) Enable an option for retail customers offering DER services as load reducers to be provided by the utility with an interval meter with capabilities comparable to those required for DER aggregators pursuant to RSA 374:4-a, I, to be used in daily load settlement; or

(b) Enable municipal or county aggregations under RSA 53-E and competitive electricity suppliers under RSA 374-F:7 to own and install revenue meters and serve as the assigned meter reader for DERs qualifying as load reducers in each electric distribution utility territory under comparable terms as those extended to DER aggregators pursuant to RSA 374-F:4-a, I.

III. Pass-Through of Transmission Price Signal for Customers and DERs.

(a) The electric distribution utilities shall make available to interval metered customers optional transmission rates that are based on their individual demand during the times that transmission charges are incurred each month.

(b) DERs qualifying as load reducers that are not receiving credit or compensation for avoided transmission costs pursuant to RSA 362-A:9 shall be compensated by the electric distribution utilities for any actual avoided regional network service (RNS) transmission charges. Such compensation shall be based on the measurement of exports to the distribution grid at the retail meter point, during the time intervals that monthly RNS charges are determined, or as otherwise necessary to compute the reduction of RNS charges to the distribution utility attributable to the DERs.

(c) The measurement of exports for calculating avoided RNS charges shall be adjusted for avoided line losses to the interconnection point where RNS charges are calculated, which shall be assumed to be same as those published for application to customer loads based on service voltage levels unless otherwise determined by the commission.

(d) The commission shall provide that the total transmission costs recovered by the electric distribution utility includes both the compensation provided to DERs qualifying as load reducers for actual avoided RNS charges and the charges to the electric distribution utility for RNS.

(e) No compensation shall be given for avoided local network service transmission charges.

IV. Modernization of Wholesale Energy and Capacity Load Estimation and Settlement Process. The electric distribution utilities, as the host utility in their respective metering domains that provide to ISO-NE each supplier's coincident peak contributions and hourly wholesale energy requirements, are responsible for addressing reasonably avoidable inaccuracies in the estimation of load and apportioning of wholesale obligations to each supplier. The commission shall commence an adjudicated proceeding within 60 days of the effective date of this section to direct the electric distribution utilities to reform their metering, load estimation, and settlement processes incorporating the following provisions:

(a) For purposes of computing wholesale energy load obligations by load asset, the metered or estimated load of each customer shall reflect their individual net load or exports to the distribution grid from DERs qualifying as load reducers during each energy market settlement interval reported to ISO-NE.

(b) For the purposes of computing daily wholesale capacity load obligations by load asset, the installed capacity or ICAP tag assigned to each customer indicating their individual share of coincident peak contribution shall reflect their individual net load or exports to the distribution grid from DERs qualifying as load reducers during the applicable time period as specified by ISO-NE for use in allocating coincident peak contributions.

(c) DERs qualifying as load reducers with a nameplate capacity of at least one megawatt may apportion percentages of their output to different load assets within the same utility service territory, pursuant to procedures approved by the commission.

(d) Submission of wholesale energy and capacity load obligation data to ISO-NE for settlements shall incorporate available interval data at the time of submission. For DERs qualifying as load reducers that are not interval metered, or for which interval meter data is unavailable, customer net load and exports to the distribution grid for each market interval shall be estimated by modifying the hourly load profile shapes for the applicable rate class of customer using the best currently available hourly production profile data for the applicable type of DER, as approved by the commission.

(e) The distribution line losses applied to exports by DERs qualifying as load reducers for this purposes of this paragraph IV shall be assumed to be one half of those published for application to customer loads based on service voltage levels unless otherwise determined by the commission.

(f) Unless permissible by ISO-NE, exports to the distribution grid from DERs accounted for as load reducers shall not exceed customer load in any load asset settlement. Any such exports in excess of customer load for a load asset shall first be proportionally distributed across the applicable supplier's other load assets in the same distribution utility service territory. Any remaining exports in excess of customer load in each settlement interval shall be socialized across all other load assets having net load in the same utility service territory as determined by the commission.

(g) Retail market operations should be standardized, and unnecessary duplication of administrative costs should be avoided. In addition to considering individual utility proposals for how to implement these reforms, the commission shall direct all electric distribution utilities to jointly solicit competitive proposals for an independent third-party to serve as their designated agent in carrying out some or all their host utility assigned meter reader and load settlement responsibilities on a statewide basis, as permissible under the ISO-NE tariff, to support common calculation of energy and capacity load obligations under this paragraph IV, to compute avoided RNS transmission costs under paragraph III, and to incorporate data from third party assigned meter readers into the settlement process pursuant to paragraphs I and II.

V. Access to Data to Enable Innovations for Customers.

(a) Each electric distribution utility is responsible for providing municipal and county aggregations under RSA 53-E and competitive electricity suppliers under RSA 374-F:7 with:

(1) All account, billing determinant, and meter data for each of their customers not less frequently than on a monthly billing cycle basis; and

(2) All data elements necessary to verify the load obligation settlement process, including hourly or sub-hourly adjustments to load to account for DER impacts, losses and other unaccounted for energy, and other adjustments to coincident peak contributions.

(b) At minimum, access to data shall be provided at the same levels of granularity and latency that are available to support electric distribution utility operations.

VI. Billing Systems to Enable Innovations for Customers. Each electric distribution utility is responsible for providing municipal and county aggregations under RSA 53-E and competitive electricity suppliers under RSA 374-F:7 with rate-ready consolidated billing services that support the use of any billing and rate design options offered to utility default service customers, including bill proration by calendar month and provision of supply credits for exports to the distribution grid by customer-generators. Time of use periods, demand structures, and dynamic rate intervals enabled for utility distribution or transmission rates must also be enabled for rate-ready consolidated billing supply rates.

VII. Implementation and Cost Recovery. The commission and electric distribution utilities are responsible for implementing paragraphs I through VI no later than November 1, 2026. The commission shall issue orders or approve tariffs to implement the provisions of this section. On a timeframe that is not less than once every 6 months after the effective date of this section until fully implemented, the department of energy and the public utilities commission shall report to the house science, technology and energy committee and the senate energy and natural resources committee regarding the status of implementation. The commission shall provide for timely cost recovery of reasonable costs that are prudently incurred by electric distribution utilities to comply with this section in distribution charges.

5 Effective Date. This act shall take effect upon its passage.

LBA
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Revised 1/31/25

HB 755-FN- FISCAL NOTE
AS INTRODUCED

AN ACT relative to the state's electric utility market.

FISCAL IMPACT: This bill does not provide funding, nor does it authorize new positions.

Estimated State Impact				
	FY 2025	**FY 2026**	**FY 2027**	**FY 2028**
Revenue	$0	$0	$0	$0
Revenue Fund(s)	None			
Expenditures*	$0	Indeterminable Increase		
Funding Source(s)	General Fund, Highway Fund, and Various Agency Funds			
Appropriations*	$0	$0	$0	$0
Funding Source(s)	None			

***Expenditure = Cost of bill** ***Appropriation = Authorized funding to cover cost of bill**

Estimated Political Subdivision Impact				
	FY 2025	**FY 2026**	**FY 2027**	**FY 2028**
County Revenue	$0	$0	$0	$0
County Expenditures	$0	Indeterminable Increase		
Local Revenue	$0	$0	$0	$0
Local Expenditures	$0	Indeterminable Increase		

METHODOLOGY:

This bill modernizes the electricity grid by allowing different energy suppliers to get specific data for pricing that changes based on demand. It also ensures that energy sources like solar panels and wind turbines, which reduce overall electricity use, are not included in certain calculations. It allows companies that manage these energy sources to install and read their own meters for selling electricity in the larger market. The bill requires a standard agreement for sharing meter information and calls for new meters that can track daily energy use more accurately. Additionally, it suggests changes to how energy use and costs are measured and requires electric companies to provide certain data to local governments. Furthermore, this bill requires the Public Utilities Commission (PUC), the Department of Energy, and the electric distribution utilities to launch and participate in adjudicative proceedings as well as requiring the Department of Energy and the PUC to make periodic reports on the progress of implementing the provisions of this bill. Finally, it mandates that electric companies offer billing services that may not currently be supported by their systems.

The Department of Energy states that this bill would require upgrades or replacements of some utility systems, including load settlement systems and customer information systems in order to fulfill the provisions of this bill. The estimated expenditures for these upgrades is deemed to be in the millions of dollars.

Additionally, according to electricity consumption data from the Department of Administrative Services, the state accounts for approximately 1 percent of all electricity purchases. Consequently, it could potentially experience 1 percent of any overall increase in electricity costs. Since the rate impact is unknown, the Department cannot provide a reasonable estimate of the potential future state, county, or local expenditures.

The PUC states that the addition of the adjudicative proceedings would have no fiscal impact on the commission.

AGENCIES CONTACTED:

Department of Energy and Public Utilities Commission