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CURRENT
ENERGY GROUP

Embedded Cost of Service Study, 2025

Narrative Methodology

Prepared for Green Mountain Power

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Introduction and Summary

This document explains the mechanics and methods relied upon within Green Mountain Power's (GMP's) Embedded Cost of Service Study (COSS) model for fiscal year (FY) 2025 (referred to as the test year for this study). Periodic preparation of a COSS is common utility practice to ensure that rate schedules are reasonably aligned with their estimated cost of service, and to inform reasonable rate structures within rate schedules.

Current Energy Group (CEG) was retained by GMP to conduct the COSS. The 2025 COSS builds upon the methods used in the previous 2018 COSS to ensure a stable baseline from which to consider potential rate schedule revenue adjustments and inform future rate design modifications. The COSS takes GMP's test year operating assets and operating expenses to calculate an annual cost of service and separates that cost of service by utility function and service classification, then allocates those costs to individual rate schedules.

The purpose of the COSS is to inform the ratemaking process by approximating the cost a utility incurs to provide service to each of its rate schedules. The COSS process by necessity incorporates judgment and assumptions, that if changed would alter results. While CEG believes this COSS study uses a reasonable set of assumptions for its results, we recognize that these results are only the first step in determining the allocation between and design of final customer rates. Within subsequent steps, it is important to ensure adjustments to customer rates are gradual and equitable to align with general ratemaking principles.

The COSS results described below, when apportioned to 2025 revenue, show only nominal allocation shifts between classes, indicating fidelity between GMP's current allocation and any changes that may be appropriately recommended after further work. These results will therefore form the basis for upcoming broader rate design review that GMP expects to undertake with CEG's assistance in 2026.

COSS Process Overview

This process begins with a detailed accounting of all operating asset values and annual operating expenses that contribute to GMP's annual revenue requirement, delineated by FERC account. The study then divides each account into annual rate schedule revenue requirements using a three-part process: ***functionalization, classification, and allocation.***

Functionalization

The first step assigns each operating cost to the basic utility function that they serve. For this study, costs are identified as serving one of the Production, Transmission, or Distribution functions.

Classification

The second level divides the functionalized costs according to the type of billing determinant appropriate in assigning each cost to ultimate customers. The classifications used in this study are Demand ($/kW of demand), Energy ($/kWh of energy), and Customer ($/month/customer). Additionally, the Peaker Substitution method is used to determine the classification split of production costs between Demand and Energy.

Allocation

After costs are identified by function and classification, they are allocated to individual rate schedules according to allocators based on each rate schedule's load characteristics and number of customers. The load characteristics and number of customers are also used to create composite, or internal, cost allocators to allocate common system costs such as overhead expenses.

GMP Rate Schedule

The COSS uses the tariffs offered in GMP's Rate Schedule ("the rate schedule") as a guide for cost allocation. The rate schedule contains multiple residential rate offerings, several supplemental rates that are offered to both residential and general service ("GS") customers, multiple GS rates, and a commercial and industrial ("C&I") rate that provides a variable voltage discount for customers taking service at primary or sub-transmission voltage. Each of these rate schedules exhibits distinct load profiles, placing different demands on the various functions of GMP's system and creating different patterns of cost causation. The various rates in the Rate Schedule are defined in Table 1.

Table 1. GMP Rate Schedule

Rate Number	Description
Rate 1	Residential
Rate 11	Residential Time-of-Use
Rate 3	Off-Peak Water Heating
Rate 13	Off-Peak Space Heating
Rate 6	GS – Non-Demand Charge
Rate 8	GS – Demand Charge
Rate 12	GS – Primary Service
Rate 15	Cable TV Attachments
Rate 63/65 – Secondary	C&I – Secondary Service
Rate 63/65 – Primary	C&I – Primary Service
Rate 63/65 – Sub-Transmission	C&I – Sub-Transmission Service
Rate 19	Street Lighting

While the COSS allocates costs to each of these rates separately, several rate schedules are within an overarching customer class. For example, Rate 1 and 11 are rate options available to the residential customer class, while Rates 63/65 are available to C&I customers and discounted based on voltage service level. It is informative when presenting the results to group related rate schedules into broader categories, given the similar customer characteristics. To that end, the study also presents aggregated results using the following categories:

- Residential: Rates 1 and 11
- GS: Rates 6 and 8
- C&I: all voltage levels of Rate 63/65
- Other: Rates 3, 12, 13, and 19

Functionalization

This study divides operating costs into three primary functions: production, transmission, and distribution. Functionalized costs categories largely map to different voltage levels of the power system. It is necessary to distinguish costs between these functions because each rate schedule has a different relative impact on the costs associated with each voltage level, depending on its operational requirements. For example, a residential customer has a much lower load factor than an industrial customer and takes service on the secondary distribution system as opposed to the primary system, so will place a relatively higher demand on the distribution system and capacity-related components of the production system, while the industrial customer will have significantly higher relative energy requirements. All three primary functional categories are summarized in Table 2.

Table 2. COSS Functions

Function	Sub-Function	Description
Production		Return on net fixed production plant assets, production-related operating, maintenance, and depreciation expenses, cost of purchased energy and capacity
Transmission		Return on net fixed assets and operating, maintenance, and depreciation expenses related to transmission of power from production plants or ISO-NE interconnection nodes to the distribution system or transmission-voltage customers
Distribution		Return on net fixed assets and operating, maintenance, and depreciation expenses related to distribution of power from the transmission system to end customers at all voltage levels and all customer service functions
	Primary	Costs related to the primary voltage-level distribution system
	Secondary	Costs related to the secondary voltage level distribution system

Distribution Voltage Sub-Functionalization

For the distribution function, it is necessary to further define costs by their sub-functionalization; because rate schedules have different patterns of cost causation on the primary and secondary distribution system, costs associated with poles, overhead and underground lines, underground conduit, and transformers are separated at this stage into primary and secondary distribution costs. GMP considers all distribution voltages under 1 kV to be secondary distribution assets, consistent with industry practices. Dividing distribution into subfunctions is necessary because different rate schedules place different levels of demand on the primary and secondary distribution systems, requiring different allocation methods for those costs. Sub-functionalization was performed by identifying the proportion of each of the above-mentioned asset categories operating at primary and secondary voltage levels and applying those proportions to the associated FERC account balances.

Classification

The second step of the COSS is to divide costs into classifications that correspond to the billing components through which customers cause costs. The primary classifications used are demand, energy, and customer costs. Additionally, this study uses the fuel offset method to determine the division between capacity and energy costs which is referred to as the peaker substitution. The fuel offset methodology divides production costs into capacity- and energy-related costs by calculating the proportion of a utility's production plant costs required to meet capacity obligations. The 2025 COSS retained the production classification split from the 2018 study.

The classification of costs are categorized as follows:

a. Demand: costs that are caused by customer and rate schedule coincident and noncoincident peak kW requirements.
b. Energy: costs that are caused by customers' total energy consumption, as measured in kWh.
c. Customer: costs that do not vary between customers and are therefore caused by the number of customers served.

Table 3 summarizes how the functional costs from Step 1 are classified.

Table 3. COSS Classifications

Function/Sub-Function	Classification		
	Demand	Energy	Customer
Production	X	X	
Transmission	X		
Distribution – Primary and Secondary Voltage	X		
Distribution – Customer-Related			X

Customer-Related Distribution Costs

Within the distribution function, there are costs that are classified as customer-related because they do not vary between customers in a rate schedule based on consumption patterns. These costs are not caused by customers' volumetric energy or instantaneous demand requirements but rather the number and type of customers in a rate schedule. For example, general administrative costs such as customer service and billing vary with the total number of customers a utility serves. Additionally, the cost to provide meters to a particular rate schedule depends on the number of customers in that rate schedule and the average cost of meter that type of customer requires.

Allocation

The final step of the COSS allocates the functionalized and classified costs to individual rate schedules. This is done through two sets of allocation factors:

a. External Allocators: these are based on test year data from the rate schedules relating to their load, customer, and other characteristics in terms of demand, energy consumption, and customer counts.
b. Internal Allocators: these are based on calculations that are internal to the COSS, wherein the initial cost allocations determined using external allocators are combined to create a second set of summary or combination allocators.

External allocators reflect the various operational characteristics that differentiate the cost causation of individual rate schedules and are generated by analyzing GMP's test year load and billing data. Internal allocators, however, are generated within the COSS itself; after a primary allocation step, costs that use internal allocators are filtered into the various external allocations that make up each internal allocator, allowing the model to express them as a function of external allocators. This is necessary because not all costs can be directly allocated through external allocators, as certain cost functions are associated with several categories of plant or expenses. For example, O&M, general plant, and overhead expenses are cost categories that are not tied to one type of plant but are caused by the need to provide services across all production or all production, transmission, and distribution plant.

Each allocator is a set of percentages that total 100%, by which each line of the COSS is multiplied to fully allocate costs to rate schedules. The primary external and internal allocators used in this COSS are summarized in Table 4.

Table 4. COSS Cost Allocators

Allocator Labels	Description
External Allocators	
Demand	

CP_12	Rate schedule average kW load during 12 monthly GMP system coincident peaks
NCP_P	Rate schedule non-coincident peak kW load on primary distribution system
CNCP_S	Sum of rate schedule customer non-coincident peak kW loads on secondary distribution system
STLGHT	Direct assignment to Rate 19 – Street Lighting
CP_ISO	Rate schedule kW load at annual ISO-NE coincident peak
Energy	
SALES	Rate schedule total billed kWh sales
ADJ_SALES	Rate schedule billed kWh sales adjusted for losses
REVREQ	Total test year rate schedule revenue
Customer	
CUST	Average number of customers in rate schedule
METR	Book value of rate schedule meters
SERV	Rate schedule NCP excluding Street Lighting
R_CUS	Average number of residential customers
RG_CUS	Average number of residential and general service customers
BILLS	Rate schedule count of annual bills
Internal Allocators	
RTBASE	Rate schedule allocated net rate base
PROD_PLT	Rate schedule allocated production plant in service
DIST_PLT	Rate schedule allocated distribution plant in service
TRNS_PLT	Rate schedule allocated transmission plant in service
DT_PLT	Rate schedule allocated distribution and transmission plant in service
PTD_PLT	Total rate schedule allocated plant in service
POLES	Rate schedule allocated poles, towers, and attachments
LABOR	Rate schedule allocated labor expenses
O_M	Rate schedule allocated operations and maintenance expenses

DISTR_OP	Rate schedule allocated distribution operations expenses
DISTR_MN	Rate schedule allocated distribution maintenance expenses

Allocations by Function

By incorporating a broad suite of allocators, the COSS is able to tailor the allocation method for each individual cost as reasonably as possible to its method of cost causation. This section describes how costs in each function are allocated, the connection between cost causation and those allocation decisions.

Production

Production costs are primarily allocated through the CP_ISO and ADJ_SALES allocators, using the capacity/energy split defined through the Fuel Offset method. This reflects the ways in which peak demand and energy consumption drive production costs. Because production costs occur before the effect of line losses, the COSS uses loss-adjusted sales to allocate the energy portion of these costs. This accounts for the fact that, because higher line-losses are realized at lower voltage levels, customers at lower voltage levels require higher energy production relative to customers taking service at the primary or sub transmission level. The COSS allocates production demand costs using the ISO-NE coincident peak because the cost of capacity in this region is largely driven by the regional capacity market.

Transmission

Transmission costs are primarily allocated through the CP_12 demand allocator. Because the transmission system is a network that must serve locational and system peaks throughout all seasons the study uses the 12-month average CP measure.

Distribution

The distribution function contains a broader variety of costs than production and transmission. Because demand-related distribution costs are caused more locally than transmission costs, the use of customer and class non-coincident peak demand allocators is more appropriate than coincident peak measures. Distribution costs caused by both primary- and secondary-voltage customers are allocated using the NCP_P allocator, which reflects the NCP on the primary system of all customers taking service at below transmission voltage. The NCP_P allocator is also used for sub-functionalized costs specific to the primary system. For costs specific to the secondary system, the COSS uses the CNCP_S allocator, which combines the individual customer NCPs for all secondary voltage customers in each rate schedule.

The distribution function also contains costs that are classified as customer-related, which are allocated based on the number of customers within a rate schedule, weight customer, or internal allocators that are more specifically tied to each cost.

Cost of Service Calculations

The final step in COSS, after all costs have been functionalized, classified, and allocated to rate schedules, is to calculate the annual total cost of service for each rate schedule. The basic formula for total rate schedule cost of service is presented below:

$$TCOS_R = R_R + E_R + T_R$$

Where:

$$TCOS_R = \text{Total Rate Schedule Cost of Service}$$

$$R_R = \text{Rate Schedule Return on Rate Base}$$

$$E_R = \text{Rate Schedule Expenses}$$

$$T_R = \text{Rate Schedule Income Taxes}$$

Rate Schedule Return on Rate Base is calculated as the portion of net rate base allocated to each rate schedule, multiplied by GMP's approved rate of return. Net rate base is defined as the sum of the book value of GMP's plant in service, intangible and regulatory assets, and construction work in progress ("CWIP"), less the sum of the Company's accumulated depreciation and regulatory liabilities. The approved rate of return is defined as GMP's weighted cost of capital, which is a weighted average incorporating the Company's costs of long- and short-term debt and the Commission-approved return on equity.

Rate Schedule Expenses are calculated as the sum of all operating, maintenance, depreciation, non-income taxes, and miscellaneous expenses allocated to each rate schedule. *Rate Schedule Income Taxes* are calculated as the sum of each rate schedules' allocated state and federal income taxes and income tax adjustments.

After calculating the total cost of service for each, this study subtracts the credits allocated to each rate schedule to calculate the final rate schedule cost of service:

$$FCOS_R = TCOS_R - C_R$$

Here *Rate Schedule Credits* are calculated as the rate schedule level allocation of GMP operating revenue not associated with billing revenue, such as net business development revenue, equity earnings in affiliates, and miscellaneous operating revenues.

With the final rate schedule cost of service calculated, the study subtracts the historical rate schedule revenue collected from each rate schedule during the test year to determine an annual sufficiency or deficiency for each rate schedule.

Results

The COSS presents results in two formats: rate schedule allocated revenue requirements and unit cost allocations. Rate schedule revenue requirement results display the full calculation of total cost of service, final cost of service, test year revenues, and revenue sufficiency or deficiency for each rate schedule, as well as the system total. Unit cost allocations display the rate schedule allocated total cost of service divided by annual billing determinants for each COSS classification, for the total system and for each COSS function.

Rate Schedule Allocations

The purpose of class allocation results is to present the annual revenue requirement for each rate schedule and compare it to the amount of test year revenue received from each rate schedule to evaluate the performance of the current rate design in generating efficient and equitable cost recovery. To demonstrate this, the COSS shows the results of each step of the cost of service calculations described above as allocated to the rate schedules:

1. Rate base
2. Return on rate base using after-tax total cost of capital
3. Expenses
4. Taxes
5. Total cost of service
6. Credits
7. Final cost of service
8. Rate schedule revenues
9. Revenue sufficiency or deficiency, presented both as a dollar amount and as a percentage of rate schedule revenues.

The final step of this calculation, rate schedule revenue sufficiency or deficiency, is equivalent to the dollar amount either over- or under-collected by GMP from each rate schedule relative to its final cost of service. The percentage result of this step shows how much more or less revenue would need to be collected from each rate schedule for it to meet its final cost of service.

Unit Cost Allocations

The unit cost results compare the system and rate schedule allocated total cost of service to the billing determinants associated with the different COSS classifications:

- Demand: rate schedule annual non-coincident peak kW load[1]
- Energy: rate schedule annual billed kWh
- Customer: rate schedule annual bills

At the system level and at each function level, this analysis divides each rate schedule's total cost of service by each billing determinant, giving an approximation of the customer rates that would be expected to recover GMP's cost of service.

Next Steps After COSS Results

The class cost results of the COSS show good correlation to GMP's current class revenue allocation. CEG understands that GMP will continue to work with CEG and state regulators in 2026 to undergo a broader rate design process that will build upon the results of this embedded COSS. Additional cost studies may provide more details on temporal cost causation and provide additional information as to how best to recover distribution and other costs through updated rate structures. The results of this study on their own are not intended to be rate design recommendations; rather they are primarily intended to inform this later work.

[1] Non-coincident peak load for unit cost results is measured at each rate schedule's primary billed service voltage.

Disclaimer

This report was prepared by Current Energy Group (CEG) to inform Green Mountain Power and the Vermont Public Utility Commission. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the author using currently available information and does not necessarily reflect those of any other entity associated with this work.

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Green Mountain Power
Fully Allocated Cost of Service Study, FY 2025
Allocated Cost of Service Results

Line	Description	System Total	Rate 1	Rate 11	Rate 13	Rate 6
	Rate Base					
1	Plant in Service	$ 2,458,409,139	$ 1,142,053,032	$ 48,873,486	$ 3,638,485	$ 260,855,641
2	Accumulated Depreciation	$ (894,974,083)	$ (412,711,391)	$ (17,225,269)	$ (1,152,253)	$ (95,043,073)
3	Rate Base Adjustments	$ 473,593,042	$ 204,018,067	$ 9,465,875	$ 593,615	$ 42,353,629
4	**Total Rate Base**	$ 2,037,028,099	$ 933,359,707	$ 41,114,093	$ 3,079,847	$ 208,166,198
5	After-Tax Rate of Return	7.36%	7.36%	7.36%	7.36%	7.36%
6	**Return on Rate Base**	$ 150,021,036	$ 68,739,155	$ 3,027,930	$ 226,822	$ 15,330,819
	Operating Expenses					
7	Operations and Maintenance Expenses	$ 630,529,454	$ 265,493,464	$ 11,528,466	$ 489,249	$ 66,188,724
8	Depreciation Expenses	$ 85,910,462	$ 40,000,434	$ 1,714,935	$ 130,442	$ 9,084,719
9	Other Taxes	$ 53,221,732	$ 24,839,682	$ 1,031,887	$ 74,591	$ 5,685,942
10	Other Expenses	$ 1,413,613	$ 659,993	$ 28,755	$ 2,284	$ 149,193
11	Income Taxes	$ 33,194,762	$ 15,498,090	$ 675,222	$ 53,630	$ 3,503,387
12	Fed Tax Adjustments	$ -	$ -	$ -	$ -	$ -
13	Total Taxes	$ 33,194,762	$ 15,498,090	$ 675,222	$ 53,630	$ 3,503,387
	Total Tax (Check)	$ 33,194,762	$ 15,498,090	$ 675,222	$ 53,630	$ 3,503,387
14	**Total Expenses**	$ 804,270,024	$ 346,491,664	$ 14,979,265	$ 750,196	$ 84,611,966
15	**Total Cost of Service before Credits**	$ 954,291,060	$ 415,230,819	$ 18,007,195	$ 977,018	$ 99,942,785
16	Total Credits	$ 113,476,103	$ 51,671,172	$ 1,977,946	$ 104,648	$ 11,773,307
17	**Cost of Service to Ultimate Customers**	$ 840,814,957	$ 363,559,646	$ 16,029,249	$ 872,370	$ 88,169,477
18	Total Current Revenues	$ 810,936,384	$ 364,800,877	$ 13,318,851	$ 494,034	$ 82,938,175
19	**(Deficiency)/Surplus**	$ (29,878,573)	$ 1,241,231	$ (2,710,398)	$ (378,336)	$ (5,231,303)
20	**(Deficiency)/Surplus % of Current Rev.**	-3.68%	0.34%	-20.35%	-76.58%	-6.31%
21	**Net Operating Income**	$ 120,142,463	$ 69,980,386	$ 317,533	$ (151,514)	$ 10,099,516
22	**Present ROR**	5.90%	7.50%	0.77%	-4.92%	4.85%

Green Mountain Power

Fully Allocated Cost of Service Study, FY 2025

Allocated Cost of Service Results

Line	Description	System Total	Rate 8	Rate 12	Rate 3	Rate 15
	Rate Base					
1	Plant in Service	$ 2,458,409,139	$ 55,643,467	$ 7,594,092	$ 28,994,129	$ 4,826,080
2	Accumulated Depreciation	$ (894,974,083)	$ (20,204,620)	$ (2,553,228)	$ (10,126,060)	$ (1,858,253)
3	Rate Base Adjustments	$ 473,593,042	$ 8,161,951	$ 1,424,023	$ 3,390,462	$ 1,035,167
4	**Total Rate Base**	$ 2,037,028,099	$ 43,600,798	$ 6,464,887	$ 22,258,532	$ 4,002,994
5	After-Tax Rate of Return	7.36%	7.36%	7.36%	7.36%	7.36%
6	**Return on Rate Base**	$ 150,021,036	$ 3,211,069	$ 476,120	$ 1,639,274	$ 294,809
	Operating Expenses					
7	Operations and Maintenance Expenses	$ 630,529,454	$ 15,896,136	$ 1,597,783	$ 5,567,489	$ 1,410,394
8	Depreciation Expenses	$ 85,910,462	$ 1,927,059	$ 267,751	$ 1,018,430	$ 168,520
9	Other Taxes	$ 53,221,732	$ 1,236,259	$ 157,383	$ 608,763	$ 106,259
10	Other Expenses	$ 1,413,613	$ 31,664	$ 4,603	$ 17,021	$ 2,673
11	Income Taxes	$ 33,194,762	$ 743,551	$ 108,097	$ 399,696	$ 62,763
12	Fed Tax Adjustments	$ -	$ -	$ -	$ -	$ -
13	Total Taxes	$ 33,194,762	$ 743,551	$ 108,097	$ 399,696	$ 62,763
	Total Tax (Check)	$ 33,194,762	$ 743,551	$ 108,097	$ 399,696	$ 62,763
14	**Total Expenses**	$ 804,270,024	$ 19,834,669	$ 2,135,618	$ 7,611,399	$ 1,750,608
15	**Total Cost of Service before Credits**	$ 954,291,060	$ 23,045,738	$ 2,611,737	$ 9,250,673	$ 2,045,416
16	Total Credits	$ 113,476,103	$ 2,703,452	$ 275,990	$ 927,392	$ 250,967
17	**Cost of Service to Ultimate Customers**	$ 840,814,957	$ 20,342,286	$ 2,335,747	$ 8,323,281	$ 1,794,450
18	Total Current Revenues	$ 810,936,384	$ 19,628,203	$ 1,661,970	$ 5,196,235	$ 1,879,099
19	**(Deficiency)/Surplus**	$ (29,878,573)	$ (714,083)	$ (673,777)	$ (3,127,046)	$ 84,649
20	**(Deficiency)/Surplus % of Current Rev.**	-3.68%	-3.64%	-40.54%	-60.18%	4.50%
21	**Net Operating Income**	$ 120,142,463	$ 2,496,985	$ (197,657)	$ (1,487,771)	$ 379,458
22	**Present ROR**	5.90%	5.73%	-3.06%	-6.68%	9.48%

Green Mountain Power
Fully Allocated Cost of Service Study, FY 2025
Allocated Cost of Service Results

Line	Description	System Total	Rate 63/65 S	Rate 63/65 P	Rate 63/65 ST	Rate 19
	Rate Base					
1	Plant in Service	$ 2,458,409,139	$ 541,325,785	$ 255,954,441	$ 81,481,189	$ 27,169,312
2	Accumulated Depreciation	$ (894,974,083)	$ (199,048,913)	$ (92,073,839)	$ (34,196,879)	$ (8,780,305)
3	Rate Base Adjustments	$ 473,593,042	$ 116,819,417	$ 55,967,496	$ 22,740,708	$ 7,622,633
4	**Total Rate Base**	$ 2,037,028,099	$ 459,096,289	$ 219,848,097	$ 70,025,018	$ 26,011,639
5	After-Tax Rate of Return	7.36%	7.36%	7.36%	7.36%	7.36%
6	**Return on Rate Base**	$ 150,021,036	$ 33,811,071	$ 16,191,156	$ 5,157,133	$ 1,915,680
	Operating Expenses					
7	Operations and Maintenance Expenses	$ 630,529,454	$ 149,144,227	$ 73,752,544	$ 37,903,913	$ 1,557,065
8	Depreciation Expenses	$ 85,910,462	$ 18,905,954	$ 8,923,253	$ 2,779,006	$ 989,958
9	Other Taxes	$ 53,221,732	$ 11,645,916	$ 5,431,852	$ 1,854,493	$ 548,706
10	Other Expenses	$ 1,413,613	$ 309,858	$ 148,423	$ 41,793	$ 17,352
11	Income Taxes	$ 33,194,762	$ 7,276,155	$ 3,485,297	$ 981,400	$ 407,475
12	Fed Tax Adjustments	$ -	$ -	$ -	$ -	$ -
13	Total Taxes	$ 33,194,762	$ 7,276,155	$ 3,485,297	$ 981,400	$ 407,475
	Total Tax (Check)	$ 33,194,762	$ 7,276,155	$ 3,485,297	$ 981,400	$ 407,475
14	**Total Expenses**	$ 804,270,024	$ 187,282,110	$ 91,741,369	$ 43,560,605	$ 3,520,556
15	**Total Cost of Service before Credits**	$ 954,291,060	$ 221,093,180	$ 107,932,525	$ 48,717,738	$ 5,436,236
16	Total Credits	$ 113,476,103	$ 25,638,364	$ 11,692,412	$ 5,640,671	$ 819,780
17	**Cost of Service to Ultimate Customers**	$ 840,814,957	$ 195,454,816	$ 96,240,112	$ 43,077,067	$ 4,616,456
18	Total Current Revenues	$ 810,936,384	$ 185,745,030	$ 82,765,658	$ 47,238,966	$ 5,269,286
19	**(Deficiency)/Surplus**	$ (29,878,573)	$ (9,709,786)	$ (13,474,455)	$ 4,161,898	$ 652,830
20	**(Deficiency)/Surplus % of Current Rev.**	-3.68%	-5.23%	-16.28%	8.81%	12.39%
21	**Net Operating Income**	$ 120,142,463	$ 24,101,285	$ 2,716,701	$ 9,319,032	$ 2,568,509
22	**Present ROR**	5.90%	5.25%	1.24%	13.31%	9.87%

Green Mountain Power

Fully Allocated Cost of Service Study, FY 2025

Allocated Cost of Service Results

Line	Description	System Total	Residential	General Service	Commercial/Industrial	Other
	Rate Base					
1	Plant in Service	$ 2,458,409,139	$ 1,190,926,518	$ 316,499,108	$ 878,761,414	$ 72,222,098
2	Accumulated Depreciation	$ (894,974,083)	$ (429,936,661)	$ (115,247,693)	$ (325,319,631)	$ (24,470,098)
3	Rate Base Adjustments	$ 473,593,042	$ 213,483,942	$ 50,515,580	$ 195,527,621	$ 14,065,899
4	**Total Rate Base**	$ 2,037,028,099	$ 974,473,800	$ 251,766,996	$ 748,969,404	$ 61,817,899
5	After-Tax Rate of Return	7.36%	7.36%	7.36%	7.36%	7.36%
6	**Return on Rate Base**	$ 150,021,036	$ 71,767,085	$ 18,541,887	$ 55,159,360	$ 4,552,704
	Operating Expenses					
7	Operations and Maintenance Expenses	$ 630,529,454	$ 277,021,930	$ 82,084,861	$ 260,800,685	$ 10,621,979
8	Depreciation Expenses	$ 85,910,462	$ 41,715,370	$ 11,011,778	$ 30,608,213	$ 2,575,101
9	Other Taxes	$ 53,221,732	$ 25,871,569	$ 6,922,201	$ 18,932,260	$ 1,495,702
10	Other Expenses	$ 1,413,613	$ 688,747	$ 180,858	$ 500,074	$ 43,934
11	Income Taxes	$ 33,194,762	$ 16,173,312	$ 4,246,938	$ 11,742,852	$ 1,031,660
12	Fed Tax Adjustments	$ -	$ -	$ -	$ -	$ -
13	Total Taxes	$ 33,194,762	$ 16,173,312	$ 4,246,938	$ 11,742,852	$ 1,031,660
	Total Tax (Check)	$ 33,194,762	$ 16,173,312	$ 4,246,938	$ 11,742,852	$ 1,031,660
14	**Total Expenses**	$ 804,270,024	$ 361,470,928	$ 104,446,635	$ 322,584,084	$ 15,768,377
15	**Total Cost of Service before Credits**	$ 954,291,060	$ 433,238,013	$ 122,988,523	$ 377,743,444	$ 20,321,080
16	Total Credits	$ 113,476,103	$ 53,649,118	$ 14,476,760	$ 42,971,448	$ 2,378,777
17	**Cost of Service to Ultimate Customers**	$ 840,814,957	$ 379,588,895	$ 108,511,763	$ 334,771,996	$ 17,942,303
18	Total Current Revenues	$ 810,936,384	$ 378,119,729	$ 102,566,377	$ 315,749,654	$ 14,500,624
19	**(Deficiency)/Surplus**	$ (29,878,573)	$ (1,469,166)	$ (5,945,386)	$ (19,022,342)	$ (3,441,679)
20	**(Deficiency)/Surplus % of Current Rev.**	-3.68%	-0.39%	-5.80%	-6.02%	-23.73%
21	**Net Operating Income**	$ 120,142,463	$ 70,297,919	$ 12,596,502	$ 36,137,018	$ 1,111,025
22	**Present ROR**	5.90%	7.21%	5.00%	4.82%	1.80%

FY25 Results: Aggregated

	System Total	Total Residential	Total GS	Total C&I	Other
		Rates 1, 11	Rates 6, 8	Rates 63, 65	Rates 3, 12, 13, 15, 19
Cost of Service to Ultimate Customers	$840,814,957	$379,588,895	$108,511,763	$334,771,996	$17,942,303
Total Current Revenues	$810,936,384	$378,117,729	$102,566,377	$315,749,654	$14,502,446
(Deficiency)/Surplus	$(29,878,573)	$(1,469,166))	$(5,945,386)	$(19,022,342)	$(3,441,679)
(Deficiency)/Surplus as a % of COS	-3.55%	-0.39%	-5.48%	-5.68%	-19.18%
Required Revenue Increase to Meet COS	3.68%	0.39%	5.80%	6.02%	23.73%
Rev. Apportionment - Increase ($)	$29,878,573	$13,619,097	$4,054,034	$11,635,784	$551,659
Rev. Apportionment - Increase (%)	3.68%	3.60%	3.95%	3.69%	3.80%
Customer Count	292,091	227,046	42,909	3,820	18,316