Public Service Commission of Maryland

Limited Income Mechanism for Utility Customers – Report

Prepared for the Commission by PC59 Work Group

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Limited Income Mechanism Report

Executive Summary

This report satisfies the directive from Commission Order Initiating Work Group to Develop Limited Income Mechanism for Utility Customers and Report (referred to as Initiating Order in this report) which established a Work Group to develop and propose a limited-income mechanism to help ensure these customers have an energy burden of approximately 6%.[1] The Work Group requests the Commission approve the consensus recommendations, decide the non-consensus issue of how credits should be issued to customers, provide guidance as to acceptable rate impacts and cost allocation, and direct the Work Group to address the Phase II issues identified in this report.

If the Commission approves the recommended mechanism prior to the end of the year it is expected that the mechanism can be developed and implemented prior to the start of 2027.

Procedural History

In 2021, the Maryland General Assembly enacted legislation directing Maryland utility companies to adopt, subject to Commission approval, mechanisms to benefit eligible limited income customers.[2] In March 2023, Potomac Edison Company ("PE") filed a rate case requesting

[1] Order Initiating Work Group to Develop Limited Income Mechanisms for Utility Customers and Report. PC59, Dec. 20, 2024. ("Initiating Order")

[2] Electricity & Gas Limited-Income Mechanisms & Assistance, H.B. 606, S.B. 392, 441st Gen. Assembly ch. 638-639 (2021) (codified at Md. Ann. Code, Pub. Util. Art. ("PUA"), § 4-309).

approval for, among other things, two low-income assistance initiatives.[3] The Commission deferred PE's low-income initiative proposals to a separate proceeding dedicated to limited-income mechanisms.[4]

The Commission subsequently initiated Public Conference 59 ("PC59") in November 2023, directing utilities, and inviting other interested persons, to comment on potential limited-income mechanisms.[5] Stakeholders submitted comments by January 31, 2024, and reply comments by February 29, 2024.[6] The Commission subsequently requested supplemental comments on these potential mechanisms and on the causes of low-income customer energy burdens in Maryland.[7] It held legislative-style hearings on September 5 and 19, 2024.[8]

Following the hearing, the Commission directed interested stakeholders to submit a list of issues for consideration by a workgroup, which Commission Technical Staff subsequently consolidated into a single list.[9] The Commission then initiated the PC59 Work Group on Energy

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[3] Potomac Edison Co.'s App. for Adj. to Retail Rates for Distrib. of Elec. Energy, Case No. 9695, Maillog No. 301935, 4 (Mar. 22, 2023).
[4] Maillog No. 305680, 1-2, 28-29 (Ord. No. 90847).
[5] Ltd. Income Mechanisms for Util. Customers, PC59, Maillog No. 306172.
[6] Maillog Nos. 307206 (Fuel Fund of Maryland ("FFM")); 307367, 307890 (Columbia Gas ("Columbia")); 307368, 307881 (Maryland Energy Advocates Coalition ("MEAC")); 307375 (American Council for an Energy-Efficient Economy ("ACEEE")); 307381 (Maryland Energy Efficiency Advocates ("MEAA")); 307390, 307909 (Washington Gas Light ("WGL")); 307391, 307907 (Potomac Edison ("PE")); 307393 (Montgomery County); 307399 (UGI Utilities); 307401, 307920 (Commission Staff ("Staff")); 307403 (Southern Maryland Electric Cooperative ("SMECO")); 307406, 307918 (Office of People's Counsel ("OPC")); 307410, 307910 (Baltimore Gas & Electric ("BGE"), Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light ("Delmarva") (together the "Maryland Exelon Utilities")); 307908 (NRG Energy); 307919 (Coalition for Community Solar Access); 307922 (Oracle Opower).
[7] Maillog Nos. 310257, 311587, at 2; see also Maillog Nos. 310902 (Civic Works Comments); 311582 (Cancer Support Foundation Comments); 311778 (Maryland Energy Administration Comments); 311778 (MEEA Comments); 311780 (Fuel Fund of Maryland Comments); 311782 (Howard County Climate Action Comments); 311785 (OPC Comments); 311788 (Maryland Department of Human Services Office of Home Energy Programs ("OHEP") Comments).
[8] Maillog Nos. 312203; 312551 (Maryland Exelon Utilities Presentation); 312540 (Maryland Exelon Utilities Resp. to Bench Data Request); 312484 (MEAC Presentation); 312491 (OPC Resp. to Bench Data Request); 312472 (ACEEE Resp. to Bench Data Request).
[9] Maillog Nos. 312452; 313130 (Columbia Gas); 313144 (Maryland Exelon Utilities); 313145 (Potomac Edison); 313157 (MEAC); 313159 (ACEEE); 313161 (OPC); 313642 (Commission Staff).

Burdens, directing it to propose a model mechanism for the Commission's consideration.[10] The Commission directed the Work Group to file its proposal by August 29, 2025, accompanied by a report identifying factors that contribute to the energy bills of limited-income customers.[11] The Commission also directed the Work Group to file an interim progress report by May 1, 2025, but an extension was granted until May 8.[12] The Commission subsequently granted an extension to file the final report until October 1, 2025.[13]

The Work Group met on a nearly bi-weekly basis since the interim report was filed, and a subgroup was established to address a supplemental study required by the Commission.

Commission Direction

The Commission directed the Work Group to propose a mechanism that conformed to § 4-309 of the Public Utilities Article (PUA), Annotated Code of Maryland, and address 15 specifics requirements when designing the mechanism. The following specifies the specific requirements.

The General Assembly directed that utility companies shall adopt, subject to Commission approval, limited-income mechanisms to benefit eligible limited customers.[14] The statute defines "eligible limited-income customer" as a residential customer with annual income at or below 175 percent of the federal poverty level ("FPL") (or 200 percent FPL for customers 67 years of age or older) or whose income meets a broader designation by the Commission.[15] The law affords broad latitude in the structure of the potential mechanism and specifically exempts it from the restrictions of PUA § 4-503(b).[16] Customers eligible for a § 4- 309 mechanism may still be eligible for other

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[10] Initiating Order
[11] *Id*. at 5.
[12] *Id*..; Maillog Nos. 317547; 317556.
[13] Letter Order, Notice of extended deadline to submit final report, PC 59, Aug. 21, 2025. Maillog No. 321767.
[14] PUA §§ 4-309(b)–(c).
[15] PUA § 4-309(a)(2).
[16] *See* PUA § 4-309(c)(2) ("Notwithstanding § 4-503(b) of this title, the mechanism may take the form of a program, tariff provision, credit, rate, rider, or other means . . . ."); *see also* § 4-503(b) ("For any service rendered . . . , a public service company may not directly or indirectly, . . . : (1) charge, demand, or receive from a person

energy assistance programs, and to the extent that a § 4-309 mechanism requires qualification by the Department of Human Services ("DHS") Office of Home Energy Programs ("OHEP"), the law directs OHEP to certify customer eligibility.[17] Factors that the Commission must consider in evaluating potential mechanisms include:

(1) the degree to which the mechanism promotes affordability of electricity or natural gas for limited-income customers;
(2) the public interest in allocating the costs of the mechanism between the utility company's shareholders and rate payers;
(3) the impact on rates, utility operating costs, customer arrearages, customer disconnections, uncollectible costs, and successful completion of payment plans;
(4) the ability of a limited-income customer to continue to receive benefits when relocating within the same service territory;
(5) coordination of benefits under the mechanism with any other public or private assistance that may be available to the customer;
(6) a minimum level of support or assistance structure to provide equitable availability of limited-income assistance across the State; and
(7) any other information the Commission considers appropriate.[18]

In addition to conformance with the mechanism's enabling statute, the Commission set forth the following guidelines or directives for the Workgroup:

(1) Standardization. The model mechanism should set forth minimum requirements that would apply statewide and allow for individual utilities to thereafter propose and implement programs based on the model mechanism.
(2) Eligibility and Enrollment. The model mechanism should be made eligible to residential utility customers based on: (a) income limits of an "eligible limited-income customer," as defined by PUA § 4-309(a)(2)(i); (b) categorical eligibility requirements utilized by [OHEP]; or (c) another form of automatic eligibility or enrollment that prioritizes ease of administration and customer access.
(3) Seasonality. The model mechanism should be applicable year-round.
(4) Mechanism. The model mechanism should be a flat or tiered discount.
(5) Applicable Charges. The model mechanism should apply to utility distribution charges and may consider application to supply charges but should not apply to arrearages at this time.

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compensation that is greater or less than from any other person under substantially similar circumstances; (2) extend a privilege or facility to a person, except those privileges and facilities that are extended uniformly to all persons under substantially similar circumstances; (3) discriminate against a person, locality, or particular class of service; or (4) give undue or unreasonable preference to or cause undue or unreasonable prejudice to a person, locality, or particular class of service.").

[17] PUA §§ 4-309(f)–(g).

[18] PUA § 4-309(e).

(6) Coordination of Benefits. The model mechanism should coordinate benefits with existing energy assistance programs to the extent practicable, including direct assistance programs, energy efficiency, and demand management.

(7) Assistance Level. The model mechanism should aim to provide a level of assistance, in coordination with other benefits, limiting the amount an eligible customer pays for applicable charges to approximately six percent of the customer's annual income.

(8) Master-Metered Apartments. The Work Group should give special consideration to the efficacy of its proposed mechanism on eligible residential utility customers residing in master-metered apartments.

(9) Cost. The Work Group should study the anticipated annual cost of the proposed mechanism, including direct costs and administrative costs. Costs should be measured both statewide and by utility. Costs should be prudently incurred.

(10) Funding. The Work Group should study the efficacy of various funding sources to meet the cost of the proposed mechanism, such as ratepayers, the Strategic Energy Investment Fund (SEIF) and proceeds thereto, state-collected penalties or fees, or new state appropriations. The Work Group's funding proposal should indicate any statutory or regulatory amendments needed to pursue such funding.

(11) Cost Recovery. To the extent that the Work Group proposes that some or all of the mechanism's prudently incurred costs be recovered from ratepayers, the model mechanism should include a proposed model for cost recovery.

  (a) Rate Classes. The proposed model should identify whether need exists for the creation of new rate classes and from which rate classes costs would be recovered.

  (b) Cost Allocation. The proposed model should recommend the appropriate allocation of costs across applicable rate classes.

  (c) Billing. The proposed model should recommend the appropriate billing method, such as a rider or surcharge, with consideration for the calculation method.

  (d) Bill Impacts. The Work Group should consider and identify anticipated bill impacts of the cost recovery model proposed.

(12) Data and Reporting. The Work Group should consider issues of data ownership, management, and transparency. The Work Group should propose reporting metrics to track compliance and evaluate the effectiveness of the mechanism.

(13) Customer Education. The Work Group should suggest customer education and outreach that will enhance the success of the mechanism.

(14) Revisions. The Work Group should propose, as applicable, bases and timetables for mechanism revisions, such as adjustments to eligibility tied to changes in the federal poverty level.

(15) Other Issues. The Work Group may study and propose additional program considerations at the discretion of the Work Group Leader.

Appendix A outlines a short description of how each point of the Commission's directive has been satisfied.

Finally, the Commission directed the Work Group to prepare a report to accompany the proposed limited-income mechanism that identifies the factors that contribute to the energy bills of limited-income customers and suggestions on ways to reduce those bills. This supplemental report is attached as Appendix E to this report.

Mechanism Design

Eligibility and Enrollment - Consensus

The Commission directed that

> the model mechanism should be made eligible to residential utility customers based on: (a) income limits of an "eligible limited-income customer," as defined by PUA § 4-309(a)(2)(i);[19] (b) categorical eligibility requirements utilized by [OHEP]; or (c) another form of automatic eligibility or enrollment that prioritizes ease of administration and customer access.[20]

To determine eligibility the Work Group recommends the mechanisms be available to all customers of a utility who are OHEP eligible as identified within the utility systems with only one caveat that customers who are flagged as benefit level 7 OHEP customers are not eligible for benefits. Under this method all OHEP customers that are identified as such with the utility who have been certified by OHEP to be at or below 200 percent of FPL will have the opportunity to receive some form of a benefit. Based on representations at the Work Group meetings, OHEP customers at benefit level 7 are above 200 percent of FPL and the Work Group members at this time elected to keep the eligibility below this level.

[19] a customer at or below 175% of the FPL or at or below 200% of the FPL if they are at least 67 years of age.
[20] Initiation Order p. 2, Item 2.

Poverty Level Classification

Poverty Level	Household Income
Poverty Level 1	0%-75% of the FPL
Poverty Level 2	>75%-110% of the FPL
Poverty Level 3	>110%-150% of the FPL
Poverty Level 4	>150%-175% of the FPL
Poverty Level 5	Subsidized Housing
Poverty Level 6	MEAP Subsidized Sub-metered Dwellings (SNAP Recipients)
Poverty Level 7	Other

This eligibility determination also satisfies the Commission’s direction for ease of administration as the utilities already are aware of which of their customers are OHEP eligible and the corresponding poverty level identifier. Therefore, as a customer's designation changes the utility can adjust the customer's participation in the mechanism.

As mentioned previously, the customer must be flagged within the utility system as being OHEP eligible. There may be some instances where an electric customer who is OHEP certified will receive no assistance through this mechanism. This may occur when customers are receiving MEAP funding (which is tied to a customer's heating source) but are not receiving EUSP funding. In this instance the electric utility would not be aware of their customers OHEP designation and thus would not include them within the final energy burden mechanism. During the Work Group OHEP indicated that less than 0.5% of MEAP customers do not receive a corresponding EUSP benefit.

Additionally, this mechanism is not extended to master meter customers currently who lack a unique account with the utilities. The Commission’s order directed the Work Group to “give special consideration to the efficacy of its proposed mechanism on eligible residential utility customers residing in master-metered apartments."[21] The Work Group examined this arrangement but determined it was not possible to incorporate these customers at this time and instead a solution to this issue could be more deeply examined at a future time. The utilities indicated the issue with trying to incorporate these individuals is that the utilities' lack telemetry into these customers individually, due to lack of account data with the utility. This means the utility lacks the ability to determine if the customer is OHEP certified and the customer's usage data, which is an important part of the overall mechanism design, especially if the credit is sized based on customer usage. Even if the utilities tried to provide a credit to customers on a master meter account, the utilities have no tracking or enforcement mechanism to ensure the credit reduces that customers' bill relative to others on the account. All other parties to the Work Group, notably OPC and MEAC, agreed that the time was not ripe for a solution to this issue and to instead focus on establishing the mechanism for non-master meter customers. It was suggested that this topic be taken up at a later time, such as a Phase II, to determine if a solution could be found. Staff requested that if this issue is to be re-examined that a party bring a proposed solution or strawman to the group for review since the group lacked a process to react to. The Work Group leader agrees that without a process for review no meaningful progress will be made. If the Work Group is directed to continue examination of this topic OPC has agreed to do research and develop a proposal for consideration. Please note that SMECO does not have any master meter customers in its service territory and PE has noted there are only 12 accounts in its service territory.

General Mechanism Structure

The Work Group proposes a tiered discount mechanism that groups customers by OHEP poverty level identification and further delineates a customer benefit by their heating source. The

[21] Initiating Order, p. 3, requirement 8.

overarching structure was put forward by Staff, OPC, MEAC, and NCLC and was generally described in the interim Work Group report. The mechanism determines the average credit a customer within a benefit level would need to receive annually to achieve a target energy burden. To make this determination each utility takes the average of the following values for each customer group by OHEP poverty level and by heating source to derive the benefit credit that will be provided to each customer within the grouping: (1) customer bills, (2) OHEP benefits received, and (3) income. Equation:

$$[\mathit{Average\ Income}] \times [\mathit{Energy\ Burden\ Percentage}] = [\mathit{Target\ Energy\ Burden\ Threshold}]$$

$$[\mathit{Average\ Applicable\ Utility\ Charges}] - [\mathit{Average\ Existing\ OHEP\ Assistance}] = [\mathit{Applicable\ Bill\ Net\ of\ OHEP\ Assistance}]$$

$$[\mathit{Applicable\ Bill\ Net\ of\ OHEP\ Assistance}] - [\mathit{Target\ Energy\ Burden\ Threshold}] = [\mathit{Discount\ Needed}]$$

Since the customer's heating source will determine the size of benefits dispersed, the amount of credit being derived from a utility for a single fuel customer versus a dual fuel customer will vary. For electric heating customers, all their credit will originate from their electric utility (thus a 6% energy burden will be used for an electric heating customer from the electric utility). For a dual fuel customer half of their energy burden will be covered by their electric utility and the other half by their gas utility (so 3% from electric and 3% from gas if a 6% energy burden is used). For example, Washington Gas will calculate 3% energy burden for all customers in their portfolio since all gas customers will also be electric utility customers. For Pepco, if a customer is identified as electric heat, then Pepco will calculate a 6% energy burden, while for a customer identified as a gas or "other" heating source, Pepco will calculate a 3% energy burden. This means natural gas utilities will have only one category of credits, electric utilities will have two - three categories of credits, and a dual fuel utility will have three - four categories of credits.

There is non-consensus regarding how the benefits are credited to each customer within a grouping as some parties favor a flat per customer bill while other parties favor a percent of rate discount. This will be discussed later in this report and will require Commission decision. Ultimately though, this credit will be provided to the customer as a rider or surcharge on the bill and does not necessitate the creation of a new rate class.[22]

By using an averaging approach this creates administrative simplicity but it does introduce some inaccuracies in the dispersion of funds since: (1) there are a range of customer usages within a benefit level such that customers who have a lower usage may receive a greater benefit than needed while higher usage customers will receive a lower benefit and (2) if the average customer in a tier level does not need a credit then no customers in that tier level will receive a benefit that year. Item one is an unavoidable outcome of creating administrative simplicity since it is not plausible to create tailored credits per customer, though this outcome can be reduced if a percent of rate discount is utilized instead of a flat credit. Item two is also a result of creating administrative simplicity but does not have as readily a mitigating solution unless the Commission was to institute a minimum credit for the class or the parties were to explore further subdividing customer groupings by usage which would create more administrative burden. No parties expressed there was a need to address the two concerns when it was identified during Work Group meetings. If the Commission tried to solve this concern with something like a minimum credit it could lead to greater likelihood of crediting more to customers than is necessary to achieve a stated energy burden goal.

As mentioned, under the mechanism there is a possibility that a customer will receive greater credit than necessary to help pay their bill, the magnitude of which may be influenced by the exact crediting approach to a customer. On a month-to-month basis this is to be expected, but it is plausible that a customer could have a large credit on their account at year end. Columbia Gas

[22] Addressing a directive from the Initiating Order, p. 4, requirement 11: Rate Classes. The proposed model should identify whether need exists for the creation of new rate classes and from which rate classes costs would be recovered.

has recommended that if a credit exists at the end of the year, any future credit would be reduced by the remaining credit. This would be like a budget bill approach for granting credits though exact specifications have not been determined at this time. Other utilities, such as the Maryland Exelon Utilities, were not sure if such adjustments would be necessary. The need for such an adjustment may be mitigated if the Commission utilizes a percent of rate reduction methodology instead of a flat rate credit approach. A continuation of the Work Group is recommended in this report to work through implementation issues and this topic may be appropriate for discussion once the Commission determines its guidance for mechanisms.

The following sections discuss the details of the proposed mechanism in more depth and highlight non-consensus issues that require a decision if the proposed mechanism is accepted by the Commission.

Sizing of Credits - Total Energy Burden

The Commission directed that:

> The model mechanism should apply to utility distribution charges and may consider application to supply charges but should not apply to arrearages at this time; and
>
> The model mechanism should aim to provide a level of assistance, in coordination with other benefits, limiting the amount an eligible customer pays for applicable charges to approximately six percent of the customer's annual income.[23]

At this time the Work Group recommends the Commission determine the appropriate energy burden year-to-year based on acceptable bill impacts after accounting for anticipated annual program costs, reconciliation of costs, and cost allocation. During this examination the utilities should provide what the cost of the mechanism is with distribution costs with and without supply costs. Some members originally opposed inclusion of supply costs into the mechanism, but after seeing the current set of estimated costs could potentially support a mechanism inclusive of

[23] Initiating Order, p. 3, requirements 5 and 7.

all costs, subject to approved cost allocation and their ability to recommend exclusions of these costs or a reduced energy burden value at a later date.

Additionally, the Work Group debated if the mechanism should cover riders and taxes, such as the bill stabilization adjustment, purchased fuel adjustments, EmPOWER, STRIDE etc… Some members such as OPC and MEAC supported these costs being included as it is part of the overall energy burden to customers and believe it is consistent with the plain language of the statute. Other parties, such as Staff were willing to include them at this time, but are worried about overall program costs and reserved the right to challenge if these costs should be included later based on final bill impacts. Please note that even if taxes and other fees are included in the mechanism to establish the credit sizes this will not eliminate a customer's obligation to pay non-bypassable taxes and fees that are based on total bill or a customer's usage.

Some discussion was held regarding customers that may be a part of retail choice and how that would impact the mechanism. It was ultimately decided this should have no impact upon sizing of the credit. The current market for residential retail choice is nearly non-existent and even if there was a robust residential choice market today suppliers are obligated to only provide Commission approved contracts to OHEP customers at or below standard offer service ("SOS").[24] Currently there are no Commission approved low-income supply contracts. To the extent an OHEP customer is with a retail supplier, their credit shall be based on SOS pricing.

As mentioned previously, the final size of credits provided to customers is determined after considering OHEP provided grants (EUSP, MEAP, and supplemental benefits) as a group. The calculation of credits shall not account for any private funds received by customers (e.g. Fuel Fund Maryland, Salvation Army, etc…) and shall not account for customer arrearages. Please note that

[24] COMAR 20.53.07.14 and 20.59.07.14.

from a customer’s perspective the bill they receive may still be higher than decision makers think. This is because most utilities do not disperse OHEP funds to customers on a monthly basis and sometimes use these funds to help reduce a customer's arrears at time of receiving the benefits. In some instances, utilities will create a budget bill for customers and disperse the OHEP funds on an even basis throughout the year while other utilities may apply the OHEP credits as one lump sum credit to a customer bill that eliminates or reduces customer’s bills until such time as the credit has been exhausted. Appendix C summarizes the individual utilities approaches to application of OHEP credits.

Ultimately, whether the mechanism should cover the entirety of a customer's energy burden up to six percent or another percentage should be examined considering resulting bill impacts to other customers on a year-to-year basis. The Work Group had robust discussions on the topic of acceptable energy burden and typically stalled at what an acceptable bill impact to customers would be. Some Work Group members argued in favor of a $2 monthly bill impact cap to other residential customers while others supported impacts up to $4 monthly bill impacts (these translate into $24 - $48 annual impacts to non-OHEP residential customers). The primary concern in these discussions is negative push back to this mechanism which could threaten the longevity of the program. All parties recommend the limited income mechanism be a separate line item on customer bills for transparency which will elevate the visibility of this mechanism. Non-OHEP customers may not appreciate or even support the enforced donation of their money to others, especially if they are themselves feeling financial constraints, or negatively view increasing rates.

Therefore, the final sizing of the credits should focus less upon inclusion of supply, fees, or taxes into the sizing of the mechanism and be determined by what is an acceptable energy burden target constrained by acceptable bill impacts to other customers that the Commission finds are in the public interest.

Flat Bill Credit versus Percent of Rate Discount - Non-Consensus

How the credit is issued to customers is a point of non-consensus. Staff, with support from SMECO, supports the issuance of a flat credit to customers.[25] Under Staff's proposal all customers within a benefit level group at a utility will receive the same credit no matter how much or little energy they use. The advantage of this approach is that it is administratively simple to implement and will minimize the amount of annual reconciliation that may be required since the only variable changing in a year from the projections are the numbers of customer participants and not usage, which is harder to predict.

All other parties support a percent of rate discount where a negative rider or credit will be applied to customer bills in the form of a negative \$/kWh or \$/therm, or a similar form, and will differ by benefit level group.[26] This will better ensure the benefit is tailored to a customer's bill which is more strictly driven by usage and minimize the likelihood of carry over credits. However, unlike the flat rate, the percent of rate discount could lead to greater volatility in the cost recovery mechanism year to year, as reconciliation may be impacted by unforeseen events. The utilities have indicated that it should cost approximately the same to program either of the solutions.

The Initiating Order also directed that "the model mechanism should be applicable year-round."[27] Either the flat or rate discount approach will be applied monthly and thus available year-round. Staff recommends if the flat discount method is approved that these credits be tailored to

[25] SMECO is willing to implement either solution but prefers the flat bill credit.
[26] To clarify the adjustment is effectively a negative credit on the bill based on customer usage or size of bill. Different utilities may have different approaches to accomplishing this outcome on the customers bill. This technical detail can be worked out during implementation.
[27] Initiating Order, p. 3, requirement 3.

be higher in the winter heating and summer cooling months when bills are highest. Such tailoring would not be necessary under a percent of rate discount approach.

Data

The data for this mechanism shall originate either from OHEP or with the utilities. From OHEP the utilities already have access to which customers are OHEP eligible, customer benefit level, OHEP benefits provided, and usage.[28] The only thing utilities do not currently have access to is customer heating source which OHEP previously indicated that it could program their systems could be provided by early 2026. The utilities would then have to program their systems to accept this information. Using this information the utilities can derive the final mechanism estimates. Additionally, the utilities do not have access to customer income. OHEP has committed to working with Staff and other Work Group members to provide the necessary information to calculate the benefit level. It is envisioned that OHEP will provide an aggregate income by benefit level to minimize personal information sharing, but there are data corrections that may need to be made before the information is utilized.

There are data quirks to be aware of and that should be considered for correction by the utilities as they are sizing the benefit levels for Commission determination. The first of these are benefit level 1 customers who OHEP has recorded as zero-income. In all practicality it is likely these customers have some form of income, but OHEP only examines the last 30 days of income to determine eligibility and in several instances the customer may not have income that month. Thus, if zero income is put into the equation for these customers the resulting benefits necessary for level 1 customers may become much more expensive and potentially overcompensate. It is recommended that zero income values be corrected in the data set, so they do not influence the

[28] The utilities still need OHEP to provide this information going forward.

calculation of credit size, or another fix is implemented. OHEP will work with Staff and other members to determine the appropriate correction to apply to this data.

Additionally, while reviewing the usage data Staff discovered outlier usage data or patterns in the data that appeared to be estimates instead of actual usage (e.g. 1 therm for some gas customers). OHEP indicated that sometimes for MEAP customers their agents will input an estimated usage (such as 1 therm) when the value is not known, and the usage level does not dictate the amount of benefit provided. It should also be noted that OHEP usage data is based on the 12 months prior to when the customer applied for OHEP eligibility and not the most recent 12 months at the time of providing data to the utilities. The utilities when sizing the benefits for their tariffs should examine the OHEP usage data for quality control and determine the most appropriate customer usage data to use to ensure it is appropriate for estimate purposes and if necessary, correct for outliers or other anomalies.

Finally, as has been noted, there can be quirks in the data and by using an average the methodology introduces error, both over and under, to accomplish the stated goal of minimizing energy burden to a set level. Staff should examine the account level data annually or every so often to conduct quality control of the data and ensure the averaging method is still accomplishing the state policy goals within reason. It is the Work Group leaders understanding that Staff is amenable to this suggestion.

Coordination with other programs

The Commission required that "the model mechanism should coordinate benefits with existing energy assistance programs to the extent practicable, including direct assistance programs, energy efficiency, and demand management."[29] The proposed mechanism is predicated upon

[29] Initiating Order, p. 3, requirement 6.

OHEP eligibility and benefits received through that program such that it is coordinated with direct assistance programs and the mechanisms that exist today. As will be discussed later in the report, there will be marketing efforts to ensure customers are aware of this mechanism which may increase OHEP participation.

Regarding other programs such as the EmPOWER energy efficiency and demand management programs the Work Group recommends there be no obligation for customers to use these programs to have access to the mechanism. Instead, the parties suggest that this be an opportunity for increased education and marketing towards these customers for these programs as an identified group who could more greatly benefit from them. Members are concerned that adding certain qualifications to use EmPOWER programs such as home audits or community solar could act as barriers to participation by creating additional obligations for these participants.[30]

Utility Program Costs

The utilities have estimated the following costs to implement the proposed mechanism which range from approximately $40,000 to $3.8 million.

Utility	**Cost**
PHI (Pepco and Delmarva)	$2.67 million +/- 50%
BGE	$3.8 million
Columbia	$1.76 million
PE	$350,000
SMECO	$50,000 and $25,000 annually
Washington Gas	$40,000 - $50,000
Total	**~$8.68 million**

[30] Columbia Gas during the Work Group was supportive of making a home audit obligation part of the program but does not oppose the final Work Group recommendation.

Washington Gas indicated that their cost estimate is driven by them currently operating a similar mechanism in Washington D.C. PHI's cost estimate reflects the unique design of Maryland's Limited Income Mechanism. Consequently, the billing system architecture used in its other jurisdictions is not applicable.

Columbia's estimate includes the implementation of a new monthly credit structure, either fixed or percentage-based, that can be adjusted to account for seasonal variations. The estimate also forecasts the costs associated with new reporting requirements, an updated cash application hierarchy to ensure accurate posting of payments and credits, and the development of new and/or revised screens within the Customer Information System. These screens will enable Columbia representatives to clearly view and explain changes to billing to customers. The estimate also includes updating the bill format to display the new payment plan/credits. As there is no existing program within Columbia's current operational footprint that aligns with the proposed solution, all components will require custom development.

PE notes that its estimate is based on past experience with implementation of similar programs for other states in their systems.

The Maryland Exelon Utilities Companies and SMECO provided an outline of the steps they will take to program their systems to accommodate the new mechanism as provided in Appendix B.

Cost of Credits

As noted previously, parties did not determine a recommended energy burden as this should be subject to Commission review after an examination of bill impacts. Therefore, the Work Group leader provides the following energy burden calculations for both supply and distribution costs assuming a 3%, 6%, and 9% energy burden to provide the Commission with a range of estimated costs. The costs are based on 2025 OHEP benefits both inclusive and exclusive of supplemental benefits. The data was corrected for zero-income customers data in level 1 and level 6. The gas usage data was also corrected where zero or one therm inputs were found but not other usage outlier corrections were applied. The calculation does not include any supplemental riders or fees/taxes such as bill stabilization adjustment, purchased cost adjustments, franchise tax, etc…[31]

Estimated Cost of Energy Burden Mechanism by Utility (Supply and Distribution)[32]

		3% Energy Burden		6% Energy Burden		9% Energy Burden	
		Supplemental Benefits Incluced	Supplemental Benefits Not Included	Supplemental Benefits Incluced	Supplemental Benefits Not Included	Supplemental Benefits Incluced	Supplemental Benefits Not Included
Electric	BGE	$ 50,387,107	$ 78,507,957	$ 28,139,382	$ 52,312,450	$ 16,621,928	$ 33,150,042
	Pepco	$ 15,321,751	$ 24,724,301	$ 7,867,831	$ 15,738,006	$ 4,722,643	$ 9,490,938
	Delmarva	$ 18,912,505	$ 26,308,755	$ 10,889,931	$ 18,257,295	$ 6,642,057	$ 11,370,643
	PE	$ 6,753,165	$ 12,537,032	$ 2,855,798	$ 6,282,449	$ 1,321,869	$ 3,432,194
	SMECO	$ 5,564,856	$ 8,184,256	$ 3,136,060	$ 5,450,108	$ 2,078,561	$ 3,479,761
Gas	BGE	$ 17,639,347	$ 28,296,097	$ 8,134,285	$ 17,839,773	$ 3,441,268	$ 10,732,648
	Washington Gas	$ -	$ 2,129,138	$ -	$ 665,668	$ -	$ 488,668
	Columbia	$ 1,468,427	$ 2,400,377	$ 457,977	$ 1,328,687	$ 163,931	$ 618,186
Total		$ 116,047,158	$ 183,087,913	$ 61,481,265	$ 117,874,437	$ 34,992,257	$ 72,763,080

Estimated Cost of Energy Burden Mechanism by Utility (Distribution Only)[33]

		3% Energy Burden		6% Energy Burden		9% Energy Burden	
		Supplemental Benefits Incluced	Supplemental Benefits Not Included	Supplemental Benefits Incluced	Supplemental Benefits Not Included	Supplemental Benefits Incluced	Supplemental Benefits Not Included
Electric	BGE	$ 18,566,195	$ 28,859,482	$ 10,400,587	$ 19,263,755	$ 6,141,291	$ 12,225,857
	Pepco	$ 6,471,260	$ 10,426,935	$ 3,331,553	$ 6,644,723	$ 1,999,815	$ 4,011,557
	Delmarva	$ 8,231,040	$ 11,444,889	$ 4,744,784	$ 7,946,103	$ 2,895,812	$ 4,952,584
	PE	$ 1,871,820	$ 3,461,898	$ 793,261	$ 1,740,652	$ 366,809	$ 950,747
	SMECO	$ 2,437,149	$ 3,581,530	$ 1,375,537	$ 2,386,775	$ 911,990	$ 1,525,103
Gas	BGE	$ 12,526,584	$ 20,094,476	$ 5,776,563	$ 12,668,916	$ 2,443,817	$ 7,621,791
	Washington Gas	$ -	$ 1,224,611	$ -	$ 382,871	$ -	$ 281,066
	Columbia	$ 1,057,030	$ 1,727,884	$ 329,669	$ 956,440	$ 118,004	$ 444,994
Total		$ 51,161,079	$ 80,821,704	$ 26,751,955	$ 51,990,236	$ 14,877,537	$ 32,013,700

[31] At the beginning of the process the utilities provided some of these values but there was no effort to ensure all of the riders and fees/taxes were accounted for.

[32] The supply and distribution rates are only inclusive of base rates and EmPOWER. This does not include other riders or taxes that would increase estimated costs.

[33] The supply and distribution rates are only inclusive of base rates and EmPOWER. This does not include other riders or taxes that would increase estimated costs.

Additionally, it is plausible that MEAP funding may be impacted by actions of the federal government. The following tables illustrate the cost implications if the mechanism is used to cover a full removal of MEAP benefits.[34]

Estimated Cost of Energy Burden Mechanism by Utility without MEAP (Supply and Distribution)[35]

		3% Energy Burden		6% Energy Burden		9% Energy Burden	
		Supplemental Benefits Included	Supplemental Benefits Not Included	Supplemental Benefits Included	Supplemental Benefits Not Included	Supplemental Benefits Included	Supplemental Benefits Not Included
Electric	BGE	$ 61,519,346	$ 81,438,496	$ 35,710,719	$ 54,878,919	$ 20,033,478	$ 34,731,412
Electric	Pepco	$ 20,266,107	$ 26,292,257	$ 11,409,978	$ 17,077,976	$ 6,198,114	$ 10,500,201
Electric	Delmarva	$ 23,104,140	$ 27,407,640	$ 15,061,930	$ 19,354,330	$ 8,450,017	$ 12,322,405
Electric	PE	$ 9,295,138	$ 13,288,253	$ 3,799,944	$ 6,794,597	$ 1,751,939	$ 3,657,340
Electric	SMECO	$ 7,050,029	$ 8,573,329	$ 4,363,776	$ 5,793,826	$ 2,720,536	$ 3,655,569
Gas	BGE	$ 35,145,256	$ 35,145,256	$ 24,679,394	$ 24,679,394	$ 16,277,545	$ 16,277,545
Gas	Washington Gas	$ 4,444,984	$ 4,444,984	$ 1,987,601	$ 1,987,601	$ 1,246,174	$ 1,246,174
Gas	Columbia	$ 3,003,036	$ 3,003,036	$ 1,930,371	$ 1,930,371	$ 1,041,276	$ 1,041,276
Total		$ 163,828,036	$ 199,593,252	$ 98,943,712	$ 132,497,013	$ 57,719,078	$ 83,431,921

Estimated Cost of Energy Burden Mechanism by Utility without MEAP (Distribution Only)[36]

		3% Energy Burden		6% Energy Burden		9% Energy Burden	
		Supplemental Benefits Included	Supplemental Benefits Not Included	Supplemental Benefits Included	Supplemental Benefits Not Included	Supplemental Benefits Included	Supplemental Benefits Not Included
Electric	BGE	$ 22,597,283	$ 29,920,658	$ 13,142,239	$ 20,193,098	$ 7,376,645	$ 12,798,486
Electric	Pepco	$ 8,543,871	$ 11,084,202	$ 4,816,375	$ 7,206,421	$ 2,618,313	$ 4,434,627
Electric	Delmarva	$ 10,049,102	$ 11,921,514	$ 6,554,329	$ 8,421,927	$ 3,679,989	$ 5,365,398
Electric	PE	$ 2,564,145	$ 3,666,498	$ 1,050,406	$ 1,880,139	$ 483,942	$ 1,012,067
Electric	SMECO	$ 3,084,677	$ 3,751,163	$ 1,910,815	$ 2,536,634	$ 1,191,888	$ 1,601,754
Gas	BGE	$ 24,958,407	$ 24,958,407	$ 17,526,074	$ 17,526,074	$ 11,559,500	$ 11,559,500
Gas	Washington Gas	$ 2,556,611	$ 2,556,611	$ 1,143,204	$ 1,143,204	$ 716,759	$ 716,759
Gas	Columbia	$ 2,161,701	$ 2,161,701	$ 1,389,555	$ 1,389,555	$ 749,550	$ 749,550
Total		$ 76,515,797	$ 90,020,755	$ 47,532,997	$ 60,297,051	$ 28,376,586	$ 38,238,142

As noted previously in the report, under the average approach customers will not receive the exact energy burden authorized by the Commission. This is driven by (1) the simplification of using an averaging approach which means there will be both over and under provision of credits and (2) the provision of an average using a fixed credit or variable credit, neither of which is directly tied to income. The following tables and charts try to illustrate this for Commission

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[34] EUSP is funded by Maryland and thus was not removed from this analysis. Associated rate impacts tables were not developed for this report.
[35] The supply and distribution rates are only inclusive of base rates and EmPOWER. This does not include other riders or taxes that would increase estimated costs.
[36] The supply and distribution rates are only inclusive of base rates and EmPOWER. This does not include other riders or taxes that would increase estimated costs.

understanding and to highlight what this mechanism will and will not accomplish. Please note that this analysis and the mechanism in general does not account for customers' arrears. The energy burden calculations assume 100% of OHEP funds are used to pay future bills instead of first deducting OHEP funds for outstanding arrears. Therefore, this analysis assumes all customers have zero arrears when determining a customer's energy burden. Also, for simplicity all benefit level 7 accounts were included in the analysis (approximately 1,500 accounts). The following analysis also includes corrections for accounts with zero-income, and where zero or one Therm usage was identified. It does not try to account for other outliers in the income or usage data.

The first table shows that approximately half of the customers that are OHEP eligible have a financial need if the target energy burden is 6%. If the need was to be met exactly with tailored credits then approximately $79 million would be provided. It also shows that more than $55 million in OHEP grants are in excess of what is needed to ensure a customer has an energy burden of 6% (assuming none of the funds are applied to arrears, which is not a correct assumption).

Number of Accounts in calculation and estimated dollar figure of 6% energy burden

Customer Group	Accounts	Need Prior to Credits
w/Energy Burden	63,991	$ 79,172,207
w/o Energy Burden	60,305	$ (55,585,061)
Total	124,296	[redacted]

The following two tables attempt to quantify the gap between how much funds would be provided to customers if 2025 fiscal year data was used to develop credits and proposed under this mechanism and then applied to customers using either a fixed credit or percent of rate approach. Using 2025 data the mechanism addressed approximately 40 - 60% of the financial need of accounts that were identified as energy burdened while approximately 25 - 50% of the funds were provided to accounts in excess of what was estimated as needed to achieve an energy burden of

6%. Ultimately based on 2025 data there would be about a reduction of approximately 23,000 - 25,000 accounts with 6% energy burden using this mechanism.

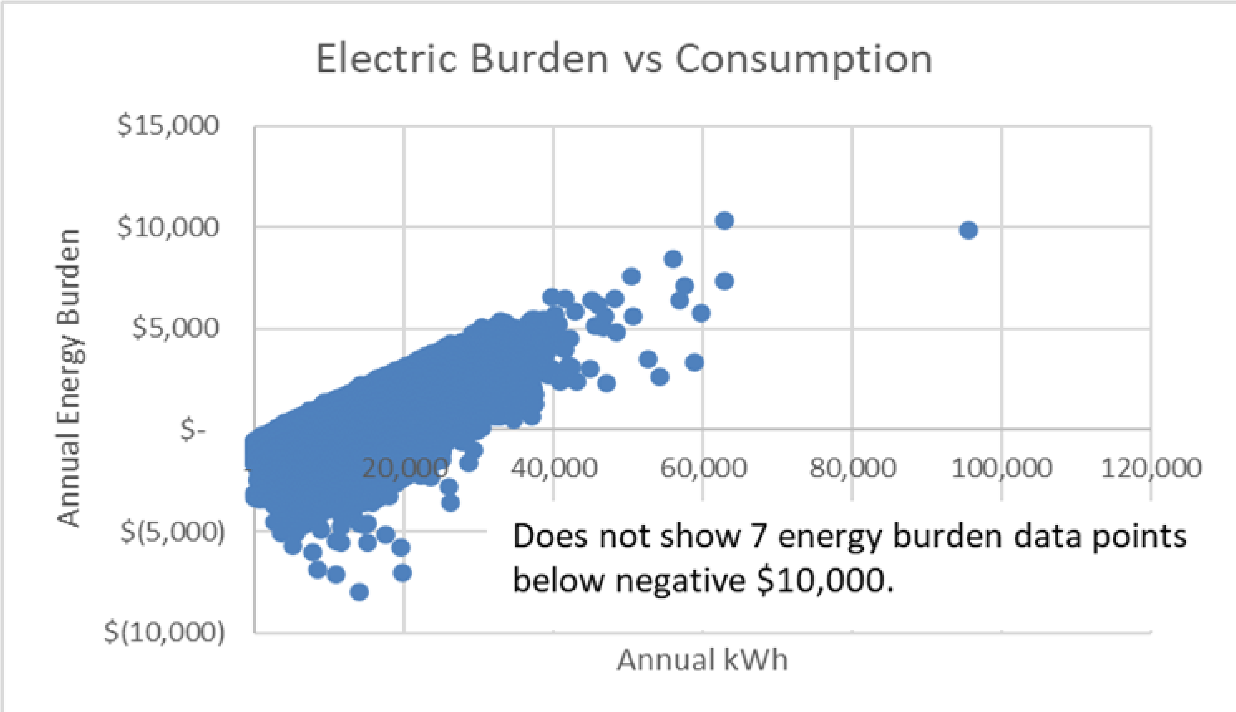
Estimated cost of credits developed from mechanism and estimated impact to customer energy burdens

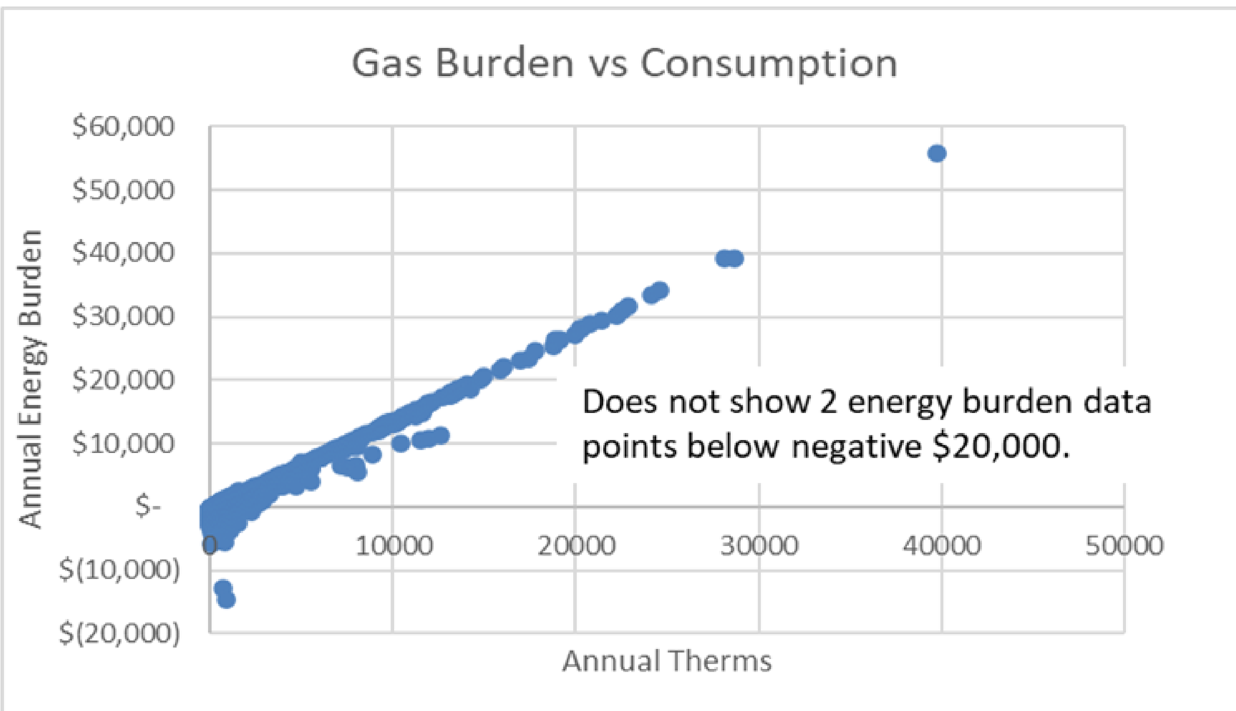
			Amount of Funds provided		Remaining Burden		Overprovision of Benefits	
Customer Group	Accounts	Need Prior to Credits	Fixed	Volumetric	Fixed	Volumetric	Fixed	Volumetric
w/Energy Burden	63,991	$ 79,172,207	$ 43,805,763	$ 52,975,939	$46,406,357	$33,340,081	$ (11,039,914)	$ (7,143,812)
w/o Energy Burden	60,305	$ (55,585,061)	$ 17,766,732	$ 8,596,556	$ -	$ -	$ (17,766,732)	$ (8,596,556)
Total	124,296	[redacted]	$ 61,572,495	$ 61,572,495	$46,406,357	$33,340,081	$ (28,806,645)	$ (15,740,369)

Impact to number of accounts with energy burden after applying mechanism

		Accounts with Energy Burden After Applying Credits	
Customer Group	Prior to provision of credits	Fixed	Volumetric
w/Energy Burden	63,991	40,670	38,332

While usage is not directly tied to income, the potential for a customer to have an energy burden will likely increase as their energy consumption increases as demonstrated by the following to figures, which plot the estimated energy burden based on usage (for simplicity this assumes half of burden is split between electricity and gas when a customer has both fuels). A possible refinement to the mechanism is that the mechanism does not trigger or the available credits are increased for customers above a certain usage threshold. This would act as a poor signal to these customers but has the potential to improve accuracy of the mechanism in achieving its stated energy burden goals. This idea has not yet been explored with the Work Group and utility cost estimates do not account for such refinement.





Funding the mechanism

The Commission also directed the Work Group to "study the efficacy of various funding sources to meet the cost of the proposed mechanism, such as ratepayers, the Strategic Energy

Investment Fund (SEIF) and proceeds thereto, state-collected penalties or fees, or new state appropriations. The Work Group's funding proposal should indicate any statutory or regulatory amendments needed to pursue such funding."[37]

During the Work Group process parties discuss the idea of redirecting SEIF funds, penalties and fees, new state appropriations, and shareholder funding in addition to ratepayer funding. The only two that the Work Group thought merited further consideration was the SEIF fund or if the legislature saw additional merit in the mechanism above the legislation it has already enacted. Outside of these two approaches all funds will need to originate from ratepayers.

The SEIF is the most obvious funding source available currently to help defer the costs of this mechanism. The SEIF is funded through the Regional Greenhouse Gas Initiative ("RGG"); Alternative Compliance Payments ("ACP") for load serving entities who do not purchase enough renewable energy credits to satisfy Maryland renewable energy portfolio standard ("RPS"); and interest on the fund.[38] Funds from the SEIF are used to fund a variety of projects and are administered by MEA. In the most recent legislative session the General Assembly enacted the Next Generation Act, which did a variety of things but notably included a modification to the SEIF that permits the refunding of ACP revenues to Maryland customers subject to the RPS goals.[39] In fact, the General Assembly dedicated the refunding of $200 million under this, and which the Commission is administering through PC 70 and Case No. 9798. To make this a more targeted refund the Commission could recommend to the General Assembly that State Government Article 9–20B–05 (e)(3) be revised to allow the MEA to redirect SEIF funds through this low-income

[37] Initiating Order, p. 4, requirement 10.
[38] Strategic Energy Investment Fund, Activities for Fiscal Year 2024, Vol. 1, Appendix A. Feb. 2025. https://energy.maryland.gov/SiteAssets/Pages/Strategic-Energy-Investment-Fund-(SEIF)-/SEIF%20Vol%201%20FY24.pdf
[39]

mechanism instead of to all ratepayers. Please note that since the funds for this originate from only electric utilities subject to the RPS standard it would need to be determined if it is appropriate for the funds to be redirected towards gas customers.

As noted in the Commission's Initiating Order, the General Assembly could enact appropriations and use taxpayer money to help fund this mechanism. This idea was supported by OPC and is a less regressive way of funding the mechanism since tax revenue is more correlated to customer incomes than energy, which is based on customer usage. That said, if this approach is recommended the General Assembly could simply funnel more money into OHEP grants such as EUSP or MEAP instead of redirecting it to the utilities. This would have a similar effect of reducing the need and cost for the proposed mechanism.

While the idea of redirecting fees and penalty revenues was discussed, ultimately the parties did not recommend this approach. The utilities pointed out that any funding source for this mechanism should be a stable source of income for year-to-year stability. Fees and penalties are not constant revenue streams and the use of them would likely lead to swings in the cost recovery mechanism. To the extent this approach is used the Commission would need to seek modifications to PUA §13–201(e) to redirect fines and fees that would either go into the Resiliency Hub Grant Program Fund, Electric Reliability Remediation Fund, or Education and Protection Fund to instead be used to fund this mechanism. The Work Group provides no recommendation if the redirection of fines and fees into these other funds represents better public use of the money.

Finally, parties discussed the idea of utility shareholder funds being used to fund the mechanism. The implementing statute requires the Commission to consider when evaluating a limited-income mechanism "the public interest in allocating the costs of the mechanism between the utility company's shareholders and rate payers."[40] It is unclear if the Commission could obligate the utilities to make shareholder funds available for this mechanism. Additionally, the Maryland Exelon Utilities made clear there was no situation in which they would make shareholder funds available to fund this mechanism. PE similarly does not support the use of shareholder funds to support this mechanism. The Maryland Exelon Utilities explained that the Companies continue to provide energy assistance program information to customers and independently formed a Customer Relief Fund to provide eligible low- and middle-income customers with one-time direct assistance. BGE and PHI provided a combined $19 million to customers in Maryland.

<u>Cost Recovery</u>

As noted above, absent modifications to statute, all costs for the mechanism will need to be recovered from ratepayers. If the Work Group proposed costs for the mechanism should be recovered from ratepayers, the Commission required the following be addressed:

(a) Rate Classes. The proposed model should identify whether need exists for the creation of new rate classes and from which rate classes costs would be recovered.[41]
(b) Cost Allocation. The proposed model should recommend the appropriate allocation of costs across applicable rate classes.
(c) Billing. The proposed model should recommend the appropriate billing method, such as a rider or surcharge, with consideration for the calculation method.
(d) Bill Impacts. The Work Group should consider and identify anticipated bill impacts of the cost recovery model proposed.[42]

High Level Cost Recovery Proposal

The Work Group recommends that the costs for the mechanism be recovered from all rate classes through a fixed-rate rider on the distribution portion of customers' bills. The Work Group

[40] PUA §4-309(e)(2).
[41] As mentioned early in the report the Commission does not need to establish new rate classes to disperse the credits.
[42] Initiating Order, p. 4, requirement 11.

proposes that customers who are eligible for the mechanism (OHEP eligible) are not required to pay the rider.[43] There is disagreement regarding cost allocation between residential versus commercial and industrial ("C&I") customers as discussed in the next section.

The rider shall recover the costs to administer the program, projected costs for the next year, and a reconciliation for costs from the previous year. Parties recommend the Commission consider a "soft cap" to the final rider to protect non-participating customers and ensure longevity of the program.

Cost Allocation

All rate classes shall help pay for the mechanism, which is permitted under the implementing legislation.[44] There is disagreement though as to what the allocation between residential and C&I customers should be. The three different proposals currently are:

(1) 25% residential and 75% C&I
(2) 75% residential and 25% C&I
(3) Let the utility decide based on the facts specific to their customer base

Those in support of 25% residential and 75% C&I as a cost allocation parameter cited to the statute that enables ratepayer funding of EUSP programs which obligates $27.4 million to be collected from C&I and $9.6 million be collected from residential customers.[45] They point to this statute as precedent for cost allocation associated with ratepayer funded limited-income programs, in the absence of a prescribed cost allocation method in PUA § 4-309. OPC has argued that the plain language of the EUSP statute and PUA § 4-309 reflect a practically identical legislative goal; and therefore advise that the EUSP statute can serve as a roadmap for the Commission to make

[43] SMECO has some concerns about excluding OHEP customers from paying for surcharges which could increase implementation costs. May slightly increase costs or elongate implementation timeline, do not have an official answer yet. SMECO prefers to include these customers but is open to how the process goes.
[44] "A proposal under this section shall allocate the prudently incurred costs of the limited-income mechanism across rate classes." PUA §4-309(d)(2).
[45] PUA § 7-512.1(e).

decisions on issues which PUA § 4-309 is silent on.[46] Additionally, the advocates point out that the implementing statute indicates that strict cost-causation need not be followed,

> "[t]he General Assembly finds and declares that the societal benefits of a well-constructed limited-income mechanism to benefit Maryland's eligible limited-income customers are in the public interest. . . notwithstanding § 4-503(b) of this title, the mechanism may take the form of a program, tariff provision, credit, rate, rider, or other means to assist an eligible limited-income customer to afford utility service."[47]

Finally, some of those in support of this allocation, notably OPC, argue that societal and non-energy benefits (such as reduced un-collectibles, terminations, and improved livelihoods from minimizing a customer choosing between essential spending that implicate health) occur due to the mechanism improving economic security and these benefits could accrue to the C&I classes. They believe the Commission should consider the full societal benefits of the mechanism and how C&I customers may benefit as justification for this split.

The groups that support the 25% residential and 75% commercial split include OPC, MEAC, NCLC, and Maryland Exelon Utilities.

Those in support of a 75% residential and 25% C&I split view this as the inverse of the EUSP statute and appropriately balance C&I interest while following the statute's guidance that costs can be allocated to all customer classes. Following strict cost causation, the implementing statute will predominately benefit the residential rate class, either because the customers in the class are receiving the benefit or it is directly reducing the potential for uncollectible costs that

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[46] As OPC notes: PUA § 7-512.1(a) provides that "[t]he Commission shall establish an electric universal service program to assist electric customers with annual incomes at or below 200% of the federal poverty level." (PUA § 7-512.1(a)) Similarly, PUA § 4-309 states that subject to Commission approval, "a utility company shall adopt a limited-income mechanism to benefit an eligible limited income customer" and an eligible limited income customer is defined as a residential utility customer with an annual income that is at or below 175%, at or below 200% if that customer is at least 67 years of age, or a broader designation approved by the Commission." (PUA §4-309)

[47] PUA § 7-4-309(b). PUA § 4-503(b) prohibits a public service company from giving preference to one class of service over another. Therefore, OPC asserts that, in implementing the limited income mechanism the Commission is permitted to prefer cost allocation to one rate class over another irrespective of strict cost-causation principles.

originate from residential ratepayers. Costs are typically allocated to the cost-causer in rate cases such that C&I customers would not directly bear the brunt of uncollected costs, though that is not a guarantee. One utility indicated that they allocated uncollectible costs directly to the class they originated from while another indicated these costs are allocated based on total revenues. The cost causation argument does not account for societal benefits though, that may accrue to C&I customers from residential customers not being terminated. It should also be noted that the limited-income mechanism statute does not provide guidance on how costs should be allocated to C&I customers except for the implication that all classes should help pay. There is no explicit link or guidance back to the EUSP statute for cost allocation. The 75% residential and 25% C&I cost allocation approach was supported by Columbia and Washington Gas.

Some parties suggested that resolving this issue now was unnecessary and instead should be left to the individual utility's discretion based on their unique customer base. For example, SMECO does not have as large C&I base as some other utilities such that they may not be as easily able to absorb a 75% cost allocation. Under this approach the utilities propose cost allocations to the Commission based on their costs to implement a set energy burden and then could determine what is the best spread of cost to effectuate the policy goals of implementing legislation based on their utility service territory and customer base. This approach was supported by PE, SMECO, Washington Gas, and Staff.

The projected bill impacts of these different scenarios is outlined in the bill impact section.

Surcharge Cap

Parties generally agree that the Commission should consider a "soft cap" on the amount of funds collected from ratepayers each year that could ultimately limit the energy burden served through the mechanism. As mentioned previously in the report proposed caps discussed in the

Work Group ranged from $2 - $4 per residential customer. Parties did not offer similar recommendations for C&I customers, though those bill impacts should also be examined when determining if the amount of energy burden served should be 6% or something less. Ultimately ensuring costs do not get too high will ensure non-OHEP customers do not face an unfair burden and ensure the longevity of the program.

Utilities wanted to ensure that the caps on cost recovery were flexible to avoid the potential for stranded costs because of reconciliation for differences between estimated and actual costs. The risk for forecast error and thus higher reconciliation increases if the Commission selects a percent of rate instead of a flat rate credit since the amount of credits in a year is more weather dependent. Parties support that under the mechanism the utilities be made whole for costs in the program.

The Commission could consider providing guidance as to bill caps they would find acceptable, which in turn will help utilities develop proposed budgets and credits in the future.

Estimated Bill Impacts

The following tables illustrate bill impacts for energy burden scenarios at 3%, 6%, and 9% using 2025 fiscal year data. The tables examine estimated residential bill impacts both with and without supplemental benefit and provide an estimate both with and without supply costs.[48] The distribution and supply costs only include base rates and EmPOWER, the examined costs of the program did not include other riders and fees/taxes which would increase these costs. Parties support including all these other riders and fees examining what the final energy burden target should be each year.

[48] The order directed the inclusion of distribution charges and that the work group could consider including supply costs.

Estimated Bill Impacts (Supply and Distribution) - With Supplemental Benefits

			With Supplemental Benefits			
			25% Res/ 75% C&I	75% Res/ 25% C&I	Previous Rate Case Allocation	100% Res
3% Energy Burden	Electric	BGE	$ 0.92	$ 2.75	$ 2.13	$ 3.67
		Pepco	$ 0.60	$ 1.80	$ 1.47	$ 2.40
		Delmarva	$ 2.33	$ 7.00	$ 6.16	$ 9.33
		PE	$ 0.60	$ 1.79	$ 1.56	$ 2.38
		SMECO	$ 0.76	$ 2.27	$ 2.20	$ 3.02
	Gas	BGE	$ 0.59	$ 1.76	$ 1.59	$ 2.35
		Washington Gas	$ -	$ -	$ -	$ -
		Columbia	$ 1.11	$ 3.33	$ 2.57	$ 4.45
6% Energy Burden	Electric	BGE	$ 0.51	$ 1.54	$ 1.19	$ 2.05
		Pepco	$ 0.31	$ 0.93	$ 0.76	$ 1.23
		Delmarva	$ 1.34	$ 4.03	$ 3.55	$ 5.37
		PE	$ 0.25	$ 0.76	$ 0.66	$ 1.01
		SMECO	$ 0.43	$ 1.28	$ 1.24	$ 1.70
	Gas	BGE	$ 0.27	$ 0.81	$ 0.73	$ 1.08
		Washington Gas	$ -	$ -	$ -	$ -
		Columbia	$ 0.35	$ 1.04	$ 0.80	$ 1.39
9% Energy Burden	Electric	BGE	$ 0.30	$ 0.91	$ 0.70	$ 1.21
		Pepco	$ 0.19	$ 0.56	$ 0.45	$ 0.74
		Delmarva	$ 0.82	$ 2.46	$ 2.16	$ 3.28
		PE	$ 0.12	$ 0.35	$ 0.30	$ 0.47
		SMECO	$ 0.28	$ 0.85	$ 0.82	$ 1.13
	Gas	BGE	$ 0.11	$ 0.34	$ 0.31	$ 0.46
		Washington Gas	$ -	$ -	$ -	$ -
		Columbia	$ 0.12	$ 0.37	$ 0.29	$ 0.50

Estimated Bill Impacts (Supply and Distribution) - Without Supplemental Benefits

			Without Supplemental Benefits			
			25% Res/ 75% C&I	75% Res/ 25% C&I	Previous Rate Case Allocation	100% Res
3% Energy Burden	Electric	BGE	$ 1.43	$ 4.29	$ 3.32	$ 5.72
		Pepco	$ 0.97	$ 2.91	$ 2.37	$ 3.88
		Delmarva	$ 3.25	$ 9.74	$ 8.57	$ 12.98
		PE	$ 1.11	$ 3.32	$ 2.89	$ 4.42
		SMECO	$ 1.11	$ 3.33	$ 3.23	$ 4.44
	Gas	BGE	$ 0.94	$ 2.82	$ 2.55	$ 3.77
		Washington Gas	$ 0.10	$ 0.29	$ 0.25	$ 0.38
		Columbia	$ 1.82	$ 5.45	$ 4.21	$ 7.27
6% Energy Burden	Electric	BGE	$ 0.95	$ 2.86	$ 2.21	$ 3.81
		Pepco	$ 0.62	$ 1.85	$ 1.51	$ 2.47
		Delmarva	$ 2.25	$ 6.76	$ 5.95	$ 9.01
		PE	$ 0.55	$ 1.66	$ 1.45	$ 2.22
		SMECO	$ 0.74	$ 2.22	$ 2.15	$ 2.96
	Gas	BGE	$ 0.59	$ 1.78	$ 1.61	$ 2.37
		Washington Gas	$ 0.03	$ 0.09	$ 0.08	$ 0.12
		Columbia	$ 1.01	$ 3.02	$ 2.33	$ 4.02
9% Energy Burden	Electric	BGE	$ 0.60	$ 1.81	$ 1.40	$ 2.41
		Pepco	$ 0.37	$ 1.12	$ 0.91	$ 1.49
		Delmarva	$ 1.40	$ 4.21	$ 3.70	$ 5.61
		PE	$ 0.30	$ 0.91	$ 0.79	$ 1.21
		SMECO	$ 0.47	$ 1.42	$ 1.38	$ 1.89
	Gas	BGE	$ 0.36	$ 1.07	$ 0.97	$ 1.43
		Washington Gas	$ 0.02	$ 0.07	$ 0.06	$ 0.09
		Columbia	$ 0.47	$ 1.40	$ 1.08	$ 1.87

Estimated Bill Impacts (Distribution) - With Supplemental Benefits

			With Supplemental Benefits			
			25% Res/ 75% C&I	75% Res/ 25% C&I	Previous Rate Case Allocation	100% Res
3% Energy Burden	Electric	BGE	$ 0.34	$ 1.01	$ 0.78	$ 1.35
		Pepco	$ 0.25	$ 0.76	$ 0.62	$ 1.02
		Delmarva	$ 1.02	$ 3.05	$ 2.68	$ 4.06
		PE	$ 0.17	$ 0.50	$ 0.43	$ 0.66
		SMECO	$ 0.33	$ 0.99	$ 0.96	$ 1.32
	Gas	BGE	$ 0.42	$ 1.25	$ 1.13	$ 1.67
		Washington Gas	$ -	$ -	$ -	$ -
		Columbia	$ 0.80	$ 2.40	$ 1.85	$ 3.20
6% Energy Burden	Electric	BGE	$ 0.19	$ 0.57	$ 0.44	$ 0.76
		Pepco	$ 0.13	$ 0.39	$ 0.32	$ 0.52
		Delmarva	$ 0.59	$ 1.76	$ 1.55	$ 2.34
		PE	$ 0.07	$ 0.21	$ 0.18	$ 0.28
		SMECO	$ 0.19	$ 0.56	$ 0.54	$ 0.75
	Gas	BGE	$ 0.19	$ 0.58	$ 0.52	$ 0.77
		Washington Gas	$ -	$ -	$ -	$ -
		Columbia	$ 0.25	$ 0.75	$ 0.58	$ 1.00
9% Energy Burden	Electric	BGE	$ 0.11	$ 0.34	$ 0.26	$ 0.45
		Pepco	$ 0.08	$ 0.24	$ 0.19	$ 0.31
		Delmarva	$ 0.36	$ 1.07	$ 0.94	$ 1.43
		PE	$ 0.03	$ 0.10	$ 0.08	$ 0.13
		SMECO	$ 0.12	$ 0.37	$ 0.36	$ 0.50
	Gas	BGE	$ 0.08	$ 0.24	$ 0.22	$ 0.33
		Washington Gas	$ -	$ -	$ -	$ -
		Columbia	$ 0.09	$ 0.27	$ 0.21	$ 0.36

Estimated Bill Impacts (Distribution) - Without Supplemental Benefits

			Without Supplemental Benefits			
			25% Res/ 75% C&I	75% Res/ 25% C&I	Previous Rate Case Allocation	100% Res
3% Energy Burden	Electric	BGE	$ 0.53	$ 1.58	$ 1.22	$ 2.10
		Pepco	$ 0.41	$ 1.23	$ 1.00	$ 1.64
		Delmarva	$ 1.41	$ 4.24	$ 3.73	$ 5.65
		PE	$ 0.31	$ 0.92	$ 0.80	$ 1.22
		SMECO	$ 0.49	$ 1.46	$ 1.42	$ 1.95
	Gas	BGE	$ 0.67	$ 2.01	$ 1.81	$ 2.67
		Washington Gas	$ 0.05	$ 0.16	$ 0.14	$ 0.22
		Columbia	$ 1.31	$ 3.92	$ 3.03	$ 5.23
6% Energy Burden	Electric	BGE	$ 0.35	$ 1.05	$ 0.81	$ 1.40
		Pepco	$ 0.26	$ 0.78	$ 0.64	$ 1.04
		Delmarva	$ 0.98	$ 2.94	$ 2.59	$ 3.92
		PE	$ 0.15	$ 0.46	$ 0.40	$ 0.61
		SMECO	$ 0.32	$ 0.97	$ 0.94	$ 1.30
	Gas	BGE	$ 0.42	$ 1.26	$ 1.14	$ 1.69
		Washington Gas	$ 0.02	$ 0.05	$ 0.05	$ 0.07
		Columbia	$ 0.72	$ 2.17	$ 1.68	$ 2.90
9% Energy Burden	Electric	BGE	$ 0.22	$ 0.67	$ 0.52	$ 0.89
		Pepco	$ 0.16	$ 0.47	$ 0.38	$ 0.63
		Delmarva	$ 0.61	$ 1.83	$ 1.61	$ 2.44
		PE	$ 0.08	$ 0.25	$ 0.22	$ 0.34
		SMECO	$ 0.21	$ 0.62	$ 0.60	$ 0.83
	Gas	BGE	$ 0.25	$ 0.76	$ 0.69	$ 1.01
		Washington Gas	$ 0.01	$ 0.04	$ 0.03	$ 0.05
		Columbia	$ 0.34	$ 1.01	$ 0.78	$ 1.35

Implementation and Process

The parties propose that the mechanism be implemented by the 2027 winter heating season. Most utilities have indicated that they can have their systems updated by September 2026 if approval is provided before the end of this year. The following table outlines the utilities estimated implementation timelines.

Utility	**Implementation Timeline**
PHI (Pepco and Delmarva)	9 - 12 Months
BGE	9 - 12 Months
PE	September 2026
SMECO	6 months after Q1 2026
Washington Gas	September 2026
Columbia	9 months

The Work Group proposes to update the credit and surcharge once each year. Each year around August/September, OHEP will provide 12 months of data to the utilities up to June 30th. The utilities will file tariffs early enough for them to be approved before the last administrative meeting of the year for a January 1 implementation date. This tariff filing will include an update for both the credit mechanism and the cost recovery surcharge. Additionally, the utilities will track spend throughout the year and track the probability of a large reconciliation. If a utility believes there is a possibility for a large reconciliation, they will make a filing to alert the Commission and advise if they believe an out-of-cycle update to the mechanism or surcharge is recommended. This annual filing is also when it is recommended for the Commission to review the mechanism to ensure it is working as designed and implement changes if needed.

The Commission should be aware of one quirk with this approach driven by the timing of OHEP's process. Between July 1 and October 15 each year OHEP has a process whereby additional awards and money are released to customers approved for the previous fiscal year which could result in (1) more customers and (2) greater monetary benefits that could be included in the cost estimate based on historical data. By not including this time period the projections for how much funding is actually needed may be distorted further. OHEP has indicated that the true up that happens during this period is inconsistent whereby the final costs estimates may or may not be impacted. If this approach was used, then utilities would not receive OHEP information until October 31 each year and would not be able to implement new credits until after February each year. Parties did not support this approach because they believed it was more important to have the mechanism updated prior to the start of the new heating season so that customers are not confused by changing benefits in the middle of the heating season.

The Work Group proposes that there be an implementation subgroup formed to work through the business processes of these tariff filings, including tariff language, how reconciliation will be conducted, and other necessary details that may arise as utilities update their systems.[49] These issues should mostly be technical implementation details.

[49] For reconciliation the parties need to determine if the reconciliation will be purely a historical reconciliation such as STRIDE or a partially projected reconciliation similar to EmPOWER.

Customer Education

The Commission directed the Work Group to suggest customer education and outreach that will enhance the success of the mechanism. The Work Group discussed this issue a couple of times and discussed that education and messaging associated with the mechanism should both focus on (1) ensuring OHEP customers are aware of the mechanism and how it operates and (2) ensuring customers who pay the surcharge understand its purpose.

OHEP eligible customers will receive this benefit so long as they are receiving an OHEP benefit with their utility. Thus, it is important that customers who are not currently registered as OHEP eligible customers but could learn the pathways to join. Additionally, it should be clear that this is different from OHEP funding.

The outreach methods will include website banners, emails, social media, flyers at community events, press releases, bill inserts (potentially) and promotion among other programs. Some utilities are concerned with the use of bill inserts since this is a more costly outreach mechanism. The Maryland Exelon Utilities provided a presentation to the Work Group that discussed proposed outreach and marketing methods.[50]

Parties also wanted to ensure that more community-based outreach be used such as the call program 211, local elected officials, local religious institutions, and schools. Several advocates pointed to the Maryland Exelon Utilities most recent outreach regarding its voluntary disbursement of $19 million to limited-and middle-income funds as a successful outreach to the impacted communities and want to build off of its success.[51]

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[50] The Maryland Exelon Utilite's presentation is attached as Appendix D.
[51] "Governor Moore Announces $19 Million in Relief for Limited- and Middle-Income Energy Ratepayers in Maryland," Jun. 12, 2025. The Office of Governor Wes Moore. https://governor.maryland.gov/news/press/pages/governor-moore-announces-19-million-in-relief-for-limited-and-middleincome-energy-ratepayers-in-maryland.aspx

Since the utilities need to program their systems for this mechanism and to allow them to tailor their marketing it is recommended that the utilities provide to the Work Group more firm education plans and marketing materials in June 2026 for feedback. The utilities will then file official educational and marketing plans with the Commission in the fall of 2026. The parties support this approach.

Phase II Work Group

For various reasons listed in this report continuance of the Work Group for a Phase II is recommended. To summarize the reasons the Work Group should continue to meet:

1. To address technical issues such as tariff language, reconciliation, and other implementation issues that may arise
2. Further deep dive master meter issues to determine if there is a way to include these customers or if this is officially not a solution for energy burden associated with this customer. As discussed previously, OPC has agreed to bring research to the Work Group regarding other States and a possible strawman for consideration.
3. Address customer education and if there are additional avenues to ensure customers are aware of this offering.

Symmetry of mechanism and cost recovery design

The Commission directed that "[t]he model mechanism should set forth minimum requirements that would apply statewide and allow for individual utilities to thereafter propose and implement programs based on the model mechanism."[52]

Parties generally agree that the mechanism should be uniform across the utilities to the extent possible. During the Work Group some utilities wanted to ensure there would be flexibility with implementing the mechanism if possible. Columbia has requested the ability to approach the Commission with potential modifications during the development phase if they determine cost savings can be achieved. They acknowledge that this would have to be reviewed and approved by

[52] Initiating Order, p. 2, requirement 1.

the Commission. As deviations from the proposed mechanism would need to be reviewed by the Commission and subsequently approved parties do not oppose the requested flexibility.

Data Collection

The Commission directed the Work Group to "consider issues of data ownership, management, and transparency… [and] propose reporting metrics to track compliance and evaluate the effectiveness of the mechanism."[53] what data should be collected to track compliance and evaluate effectiveness of the mechanism.

The Work Group proposes that most data collection be added to the excel templates reported to the Commission for PC53. This will allow for tracking of most metrics monthly and at a zip code level. One data point will be tracked in DHCD's semi-annual EmPOWER reports.

There is one data point that is under contention. OPC has requested the following be tracked in the PC53 data reporting templates:

> Average bill of participating customers before and after the bill discount is applied, by zipcode.

The utilities are not favorable to this request since they would be required to program their systems to create and collect the data, whereas most of the other reporting requested does not require the creation of data. During Work Group meetings the utilities sounded amenable to providing this data annually. OPC believes the information is more useful when used in conjunction with the PC53 data reporting, which is reported on a monthly cadence, and does not have any insight into why it would be more costly/difficult to develop the requested data on a monthly basis as opposed to an annual basis. So, in the absence of this information, OPC continues to support the provision of all reporting data discussed below, by month

[53] Initiating Order, p. 5, requirement 12.

Data points to be tracked monthly in PC53 reporting

- the number of households participating in the mechanism, by zip code.
- the number of customers participating at each qualification level (level 1, level 2, etc.) by zip code.
- Average monthly usage for participating customers, by zip code.
- Total $ for monthly credits, per zip code.
- The number of customers who receive the monthly credit that are disconnected in each month, by zipcode.

Data points to be tracked through DHCD semi-annual filing. DHCD has agreed to this proposal. OPC requests the Commission direct DHCD to report the information as described in DHCD's semi-annual empower reports:

- DHCD will include the requested information in DHCD's semi-annual EmPOWER reports. In those reports DHCD will include:
    - the number of customers participating in the PC59 limited-income mechanism that submitted an application to DHCD for a home energy audit (by zipcode, if feasible), and
    - the number of customers participating in the PC59 limited-income mechanism who participated in a home energy audit (by zipcode, if feasible). In the final PC59 WG Report to the Commission please include that.
- Non-consensus data point
    - Average bill of participating customers before and after the bill discount is applied, by zipcode.

<u>Conclusion</u>

The Commission should approve the consensus issues, provide guidance on the non-consensus issues and direct the Work Group to engage on the Phase II items and for the utilities to develop their systems to implement the proposed mechanism by September 2026.

Appendix A - Summary of Report Compliance with Initiating Order

	Commission Requirements	Proposal
1	Standardization. The model mechanism should set forth minimum requirements that would apply statewide and allow for individual utilities to thereafter propose and implement programs based on the model mechanism.	Parties generally support standardization though Columbia has requested flexibility to approach Commission with modifications to the proposal if during development cost savings can be achieved. Parties were O.K. with this subject to Commission review.
2	Eligibility and Enrollment. The model mechanism should be made eligible to residential utility customers based on: (a) income limits of an "eligible limited-income customer," as defined by PUA § 4-309(a)(2)(i);2 (b) categorical eligibility requirements utilized by the DHS Office of Home Energy Programs (OHEP);3 or (c) another form of automatic eligibility or enrollment that prioritizes ease of administration and customer access.	Customers identified by OHEP as poverty level 6 or lower which is effectively 200% FPL or lower. See eligibility section of report for more information.
3	Seasonality. The model mechanism should be applicable year-round.	Mechanism will be available year round. If a percent of rate method is selected then benefit will fluctuate with customers by usage. If a flat credit mechanism is selected then Staff recommends the credit be tailored to be higher in the cooling and heating seasons.
4	Mechanism. The model mechanism should be a flat or tiered discount.	The benefits will scale based on customers' identified OHEP poverty level. There is non-consensus if the credit should be provided as a flat credit or a percent of rate credit.

	Commission Requirements	Proposal
5	Applicable Charges. The model mechanism should apply to utility distribution charges and may consider application to supply charges but should not apply to arrearages at this time.	Parties support the Commission evaluating benefits inclusive of all charges and then determining if the final energy burden credit provided should be limited based on the cost of the program. This would be a moving target. See report for more details about this.
6	Coordination of Benefits. The model mechanism should coordinate benefits with existing energy assistance programs to the extent practicable, including direct assistance programs, energy efficiency, and demand management.	The amount of credits provided to customers account for OHEP benefits provided in the previous fiscal year. It will not account for private benefits (e.g. Fuel Fund MD) Co-marketing should be done for EmPOWER, community solar, and other programs but majority parties do not support obligating participation in these other programs to receive the credit.
7	Assistance Level. The model mechanism should aim to provide a level of assistance, in coordination with other benefits, limiting the amount an eligible customer pays for applicable charges to approximately six percent of the customer's annual income.	Parties do not have an alternative recommendation regarding the amount of energy burden covered through the mechanism at this time. Instead parties recommend the Commission evaluate the cost of the credits annually using a 6 percent energy burden (inclusive of OHEP benefits from the previous fiscal year) and then determine the amount of benefit that can be provided at acceptable bill impact levels.
8	Master-Metered Apartments. The Work Group should give special consideration to the efficacy of its proposed mechanism on eligible residential utility customers residing in master-metered apartments.	Cannot include master meter accounts at this time where customers do not have accounts with the utility. See report for more information.

	Commission Requirements	Proposal
9	Cost. The Work Group should study the anticipated annual cost of the proposed mechanism, including direct costs and administrative costs. Costs should be measured both statewide and by utility. Costs should be prudently incurred.	See report for range of costs.
10	Funding. The Work Group should study the efficacy of various funding sources to meet the cost of the proposed mechanism, such as ratepayers, the Strategic Energy Investment Fund (SEIF) and proceeds thereto, state-collected penalties or fees, or new state appropriations. The Work Group's funding proposal should indicate any statutory or regulatory amendments needed to pursue such funding.	See report for suggestions regarding funding sources other than residential customers. The only alternative funding sources identified were the SEIF or the General Assembly developing a new funding stream.
11	Cost Recovery. To the extent that the Work Group proposes that some or all of the mechanism's prudently incurred costs be recovered from ratepayers, the model mechanism should include a proposed model for cost recovery.	The Work Group recommends a transparent fixed surcharge for all non-OHEP customers. See report for more details.
12	Rate Classes. The proposed model should identify whether need exists for the creation of new rate classes and from which rate classes costs would be recovered.	The Work Group recommends no new rate class. The Work Group recommends all rate classes pay for the mechanism.
13	Cost Allocation. The proposed model should recommend the appropriate allocation of costs across applicable rate classes.	There is non-consensus regarding how costs should be allocated amongst the customer classes. See report for the different view points on this issue.

	Commission Requirements	Proposal
14	Billing. The proposed model should recommend the appropriate billing method, such as a rider or surcharge, with consideration for the calculation method.	The Work Group recommends a transparent surcharge that updates once a year that will be billed as a fixed rate to customers.
15	Bill Impacts. The Work Group should consider and identify anticipated bill impacts of the cost recovery model proposed.	See report and appendices for estimated bill impacts under different scenarios.
16	Data and Reporting. The Work Group should consider issues of data ownership, management, and transparency. The Work Group should propose reporting metrics to track compliance and evaluate the effectiveness of the mechanism.	See report for data and reporting recommendations.
17	Customer Education. The Work Group should suggest customer education and outreach that will enhance the success of the mechanism.	See report for recommendations regarding next steps for customer education.
18	Revisions. The Work Group should propose, as applicable, bases and timetables for mechanism revisions, such as adjustments to eligibility tied to changes in the federal poverty level.	The Work Group recommends the mechanism and surcharge be revised once a year and if changes are necessary make them then. Utilities should track the need for reconciliation throughout the year and approach the Commission out of cycle if there is the potential for a large reconciliation. Staff can also get access to account level data from OHEP and can test the success of the mechanism at achieving Commission's stated energy burden goals every so often.
19	Other Issues. The Work Group may study and propose additional program considerations at the discretion of the Work Group Leader.	See report for more nuanced description of mechanisms and surcharge.

	Commission Requirements	Proposal
20	In addition, the Work Group shall also prepare a report to accompany the proposed limited-income mechanism that identifies the factors that contribute to the energy bills of limited-income customers and suggestions on ways to reduce those bills.	See Appendix E.

Appendix B - Maryland Exelon Utilities IT Project Scope Summary and SMECO IT Project Scope

Maryland Exelon Utilities Project Phase Details:

- **Planning Phase**
  - During the Planning Phase, stakeholders from various departments collaborate to define project requirements, ensure OHEP data completeness, and outline technical needs for customer billing system integration and regulatory compliance. The phase emphasizes cross-functional alignment, data validation, audit trails, and adherence to Maryland PSC's PC59 energy burden targets.

- **Design Phase**
  - During the Design Phase, the project team translates requirements into detailed technical specifications. This includes designing customer billing system logic for calculating credits, defining new tables for customer eligibility and benefit tiers, and ensuring data integration for regulatory compliance. The phase also involves planning communication materials, updating user interfaces for customer support, and developing reports to track program effectiveness and meet reporting standards. Cross-departmental collaboration ensures the design aligns with both internal needs and regulatory expectations.

- **Build Phase**
  - During the Build Phase, the project team develops and configures key system components, including the implementation of customer billing system logic for the bill credit application, construction of tables for eligibility and benefit tiers, and integration with OHEP and billing systems. The phase also emphasizes error handling, coordination with related teams, and maintaining a prioritized backlog to ensure all technical and reporting requirements are met ahead of deployment.

- **Testing Phase**
  - During the Testing Phase, the focus is on thoroughly validating system functionality and integration. Teams test individual and end-to-end processes, including credit logic, billing scenarios, and regulatory reporting. User Acceptance Testing involves multiple departments to ensure accuracy and compliance. All defects must be addressed before launch, with detailed test evidence collected for audit and regulatory review.

SMECO Project Phase Details*:

There is still some uncertainty as far as the implementation timing and costs, depending on what requirements are needed or how things develop. However, the project would include the following phases:

- Planning Phase – SMECO works with the contractor (USP) and stakeholders to define requirements.
- Design Phase – During this phase, SMECO will ensure our Customer Care and Billing (CC&B) system is configured to meet the needs and reporting requirements for PC59. SMECO will develop test cases to be used during the Testing Phase.
- Build Phase – SMECO's contractor will make changes and configurations in a test environment to both CC&B and WebMethods (or middleware software).
- Testing Phase – During the testing phase, changes will be fully tested (in a test environment), and bill print will be verified.
- Implementation Phase – During this phase, SMECO will implement the tested configuration in our Production environment.

**Note: SMECO is currently engaged in an upgrade to our CIS system from CC&B to C2M. Estimated Go-Live at this time is late Q1 2026.*

Appendix C - Utility Treatment of OHEP Funds

Maryland Exelon Utilities:

For EUSP benefits, the Maryland Exelon Utilities will first apply an OHEP benefit to any arrears the customer has. The reminder of the benefit is then spread out over 12 months. Arrears retirement benefits are applied all at once. For MEAP, benefits the Maryland Exelon Utilities apply the benefit as a lump sum and if the customer is also a part of the USPP program then they are put on budget billing.

Columbia:

If the customer is going on USPP. Arrears are paid off first with the MEAP grant and/or GARA funds. Any overage of MEAP reduces their payment plan from budget to budget - 1/12 remaining MEAP grant. If no arrears, the MEAP grant reduces their payment plan from Budget to budget -1/12th of MEAP grant. If arrears still exist, customers are entered into agreements that include a supplemental payments for the balance.

If a customer does not go on USPP: MEAP pays to reduce arrears first. Any remaining (Including if there were no arrears) goes on account in a lump sum and will remain as a credit, if necessary, until the full MEAP benefit is utilized. If arrears still exist after funds are applied there will be a 30 day delay on collection activity and then collections may resume if no payment is received.

PE:

Customers seeking assistance with arrears after receiving energy assistance may: Have the remainder of EUSP or MEAP grants applied to their account balance if it is currently being applied in 1/12 th increments toward the current bill.

Receive a 3-month installment plan. An upfront payment of 50% of the termination amount is required if there is a pending termination. If no pending termination, 50% of the balance is required for the upfront payment.

Washington Gas:

OHEP benefits would go to the oldest balance first, being applied to any arrears the customer has. Once covered, any remainder would then go to current charges. If there is still a remaining OHEP benefit, that would be issued as a credit to the account for any subsequent usage until used in its entirety.

SMECO:

When the grant is received and the customer **selects USPP**

- Arrears are paid off first with the MEAP grant. Any remaining MEAP grant is goes as a credit toward next month(s) bill. If there is debt remaining it is enrolled in a 12 month payment arrangement (PASA).
- Customer is enrolled in a budget.

- EUSP Payments are applied to a customer's account 1/12 at a time for 12 months. If the customer contacts SMECO and requests the EUSP payment be applied to the full balance, SMECO will do so.

When the grant is received and the customer **selects NO to USPP**

- If customer is currently enrolled on a budget, SMECO leaves them on budget and recalculates their monthly installment.
- If the customer is not currently on a budget, SMECO does not start budget or PASA (if there's a balance). However we note the customer's account " Customer said NO to USPP (Utility Service Protection Program) on OHEP application. Did not setup OHEP Budget or OHEP PASA."

Supplemental EUSP or MEAP funds

- Posted as a payment to reduce any arrear or a credit toward future bills (if the customer owes less than the Supplement).

Appendix D - Details of a Limited-Income Mechanism and C&I bill impacts

See attachments

Appendix E - Cost Driver Report

See Attachment

Appendix F – Maryland Exelon Utility Marketing Presentation

See Attachment