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|  | **PENNSYLVANIA****PUBLIC UTILITY COMMISSION**Harrisburg, PA. 17105-3265 |  |

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|  | Public Meeting held December 19, 2019 |
| Commissioners Present: |  |

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| Gladys Brown Dutrieuille, Chairman |  |
| David W. Sweet, Vice ChairmanAndrew G. Place |  |
| John F. Coleman, Jr.  |  |
| Ralph V. Yanora |  |
|  |  |
| 2021 Total Resource Cost (TRC) Test | M-2019-3006868 |

**FINAL Order**

**BY THE COMMISSION:**

 Act 129 of 2008, 66 Pa. C.S. § 2806.1, directs the Pennsylvania Public Utility Commission (Commission) to analyze the benefits and costs of the energy efficiency and conservation (EE&C) plans that certain electric distribution companies (EDCs) are required to file. Our September 19, 2019 *2021 TRC Test Tentative Order* at this docket proposed methodology and requested comments on a 2021 TRC Test for use in planning for and during a potential Phase IV of Act 129. This Order finalizes the specific refinements to the 2021 TRC Test for use in Phase IV of Act 129, that, if approved, would begin June 1, 2021.[[1]](#footnote-2)

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# BACKGROUND AND HISTORY

Act 129 requires EDCs with 100,000 or more customers to adopt an EE&C plan, subject to approval by the Commission, to reduce electric consumption. The initial EE&C plans, effective from June 1, 2009, to May 31, 2013, were designated Phase I of Act 129. For Phase I, Act 129 required that an analysis of the benefits and costs of each EDC’s EE&C plan, in accordance with a TRC Test, be approved by the Commission. Act 129 required each EDC to demonstrate that its plan was cost-effective using the TRC Test and required that the EDC provide a diverse cross-section of alternatives for customers of all rate classes. 66 Pa. C.S. § 2806.1(b)(1)(i)(I).

Similarly, for subsequent phases, the Commission is charged with determining whether to establish conservation and peak demand reduction requirements and, if so established, to determine if EDCs have met the requirements.[[2]](#footnote-3) Act 129 also addresses energy efficiency (EE) and demand reduction targets from June 1, 2013, forward. 66 Pa. C.S. §§ 2806.1(c)(3) and 2806.1(d)(2).[[3]](#footnote-4)

For Phase II of Act 129 (Phase II), which covered the period from June 1, 2013, to May 31, 2016, the Commission adopted three-year consumption reduction requirements, as recommended by the Phase I Statewide Evaluator (SWE),[[4]](#footnote-5) that varied by EDC based on the specific mix of program potential, acquisition costs, and funding available under the 2% limitation stipulated by Act 129.[[5]](#footnote-6) The Phase I SWE produced an *Energy Efficiency Market Potential Study*[[6]](#footnote-7) to document the methodology, assumptions, inputs, and analytical methods used to arrive at the recommended consumption reduction goals for each EDC.

The Commission directed the Phase I SWE to study the cost-effectiveness of current and potential future demand response (DR)[[7]](#footnote-8) programs. On November 1, 2013, the Phase I SWE’s *Act 129 Demand Response Study* was released.[[8]](#footnote-9) For Phase II, there were no DR requirements, however, the Commission also directed the Phase II SWE[[9]](#footnote-10) to study the cost-effectiveness of potential future DR programs. On February 27, 2015, the Phase II SWE’s *Demand Response Potential Study*[[10]](#footnote-11) was released. In both studies, the SWE collected data and documentation from EDCs to aid in performing an analysis of the cost-effectiveness of compliance with the current legislative DR requirements and of potential improvements to the DR program design.

Act 129 also required that the Commission determine if EE and DR goals should be established beyond the Phase II goals. 66 Pa. C.S. §§ 2806.1(c)(3) and 2806.1(d)(2). Phase III goals were determined in the Phase III Implementation Order at Docket No. M‑2014-2424864.[[11]](#footnote-12) To support implementation and the benefit/cost (B/C) analyses for Phase III of Act 129, the Commission adopted the 2016 TRC Test at *2016 TRC Test Order*, Docket No. M‑2015-2468992 on June 22, 2015.[[12]](#footnote-13) Phase III of Act 129 covers June 1, 2016, to May 31, 2021.

If the Commission decides to proceed with Phase IV of Act 129 (Phase IV), it will be necessary to address the B/C measurements for Phase IV. In order to allow for adequate planning for a potential Phase IV, the Commission has chosen to put forth this Final Order regarding a 2021 TRC Test, which builds on the four previous Pennsylvania TRC Test Orders and industry documents, such as the 2002 *California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects*[[13]](#footnote-14)(*California Manual*),for the B/C analysis of EE&C plans for a potential Phase IV. We note that we also adopted a 2021 Technical Reference Manual (TRM) at Docket No. M­2019-3006867 (order entered August 8, 2019), for use if we decide to proceed with a Phase IV.

Pennsylvania conducts the requisite B/C analyses using a TRC Test. The TRC Test for Phase I of Act 129 was adopted by Commission Order at Docket No. M­2009­2108601 on June 23, 2009 (*2009 TRC Test Order*). The TRC Test was refined at the same docket on August 2, 2011 *(2011 TRC Test Order),* and on August 30, 2012, at Docket No. M-2012-2300653 *(2013 TRC Test Order).* The TRC Test was last updated on June 22, 2015, at Docket No. M-2015-2468992 by the *2016 TRC Test Order*.

In some of our previous TRC Test Orders, we have provided instructions and guidance in a way that refers readers to prior TRC Test Orders – particularly for issues on which we are not proposing any changes. Various stakeholders have commented that this style makes it challenging to follow the current instructions and guidance on complex technical topics because instructions and directions are distributed across multiple documents. In the development of this Final TRC Test Order for Phase IV, we have attempted to provide all instructions in a comprehensive document. Appendix C additionally summarizes the Commission’s decisions by topic in a manner that is consistent with the structure of this Order. The evolution of the Commission’s perspective on issues that have been discussed and addressed previously are summarized herein for completeness. Our discussion below also addresses those elements from the 2016 TRC Test Order for which we have proposed and made changes.

**2021 Technical Reference Manual (TRM) and Phase IV TRM Final Order**

 The 2021 TRM is the guide that will be used to measure and verify applicable EE and Demand Side Management (DSM) measures used by EDCs to meet the Act 129 consumption and peak demand targets. While its use will continue to provide the necessary information that establishes the evaluation process to monitor and verify data collection, quality assurance, and the results of each EDC’s EE&C plan, it also provides information that will assist EDCs in their TRC calculations.

The Commission proposed an update to the TRM on April 11, 2019, Docket No. M-2019-3006867, and the final version was adopted on August 8, 2019.

# TRC TEST EXPLAINED

Act 129 defines a TRC test as “a standard test that is met if, over the effective life of each plan not to exceed 15 years, the net present value (NPV) of the avoided monetary cost of supplying electricity is greater than the NPV of the monetary cost of energy efficiency conservation measures.” 66 Pa. C.S. § 2806.1(m). Thus, the TRC test is a critical measuring tool in determining the cost-effectiveness of an EDC’s EE&C plan. Historically, the TRC test has been a regulatory test. It is not a static, one-size-fits-all tool. It can incorporate different factors and evaluate variables in different ways, as determined by the jurisdictional entity using it. Pennsylvania has tailored its TRC test over time to evaluate EDC progress in meeting the requirements of Act 129, consistent with the policy objectives of the Commonwealth within the statutory directives of Act 129.

The purpose of using a TRC test to evaluate EE&C programs is to track the relationship between the benefits to the Commonwealth and the costs incurred to obtain those benefits. Sections 2806.1(c)(3) and 2806.1(d)(2), as well as the definition of the TRC test in Section 2806.1(m) of Act 129, provide that a TRC test be used to determine whether ratepayers, as a whole, received more benefits (in reduced capacity, energy, transmission, and distribution costs) than the implementation costs of the EE&C plans.

In Pennsylvania, the TRC Test considers the combined effects of an EDC’s EE&C plan on both participating and non-participating customers based on the costs incurred by both the EDC and any participating customers. In addition, the benefits calculated for use in the TRC Test include the avoided supply costs, such as the reduction in generation valued at marginal cost for the periods when there is a consumption reduction, and the avoided cost of generation, transmission, and distribution capacity for measures that reduce peak demand. In addition to the avoided cost of supplying electricity, the avoided cost of supplying fossil fuel and water are included in the algorithms for calculating TRC benefits. These avoided costs apply to EE&C measures that impact consumption of those resources. Avoided supply costs, depending on the mandate in each jurisdiction, can be calculated using either gross or net program savings. In Pennsylvania, we have primarily looked at avoided supply costs from the perspective of gross program savings, which is how Act 129 compliance targets are measured.

Further, the costs used in the TRC Test include the costs of the various programs paid by an EDC (or its Conservation Service Provider [CSP]) and the participating customers[[14]](#footnote-15) and reflect any net change in supply costs for the periods in which consumption is increased in the event of load shifting. Thus, for example, equipment, installation, operation and maintenance (O&M) costs, cost of removal (less salvage value), and administrative costs, are included – regardless of who pays for them.

 The results of the TRC Test are expressed as both a present value of net benefits (PVNB) and a B/C ratio. The PVNB is the present value of the net benefits (benefits minus costs) of this test over a specified period (*i.e.*, the expected useful life of the energy efficiency measure). The PVNB is a measure of the change in the total resource costs due to the program. A PVNB above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based. A discount rate must be established to calculate the NPV. Historically, the discount rate for the Pennsylvania TRC Test is the EDC’s weighted average cost of capital. The Commission has changed the discount rate for Phase IV, as discussed in Section A.4.

The B/C ratio is the ratio of the discounted total benefits of the program to the discounted total costs over the expected useful life (up to a maximum of 15 years) of the energy efficiency measure, program, or portfolio. The B/C ratio gives an indication of the rate of return of this program to the utility and its ratepayers. A B/C ratio greater than one indicates that the program is beneficial to the utility and its ratepayers on a TRC basis.[[15]](#footnote-16) The explicit formulae for use in Pennsylvania are set forth in Appendix A of this order.

As discussed in prior TRC Test Orders, the *California Manual* was the starting point for the Pennsylvania TRC Test but does not address all issues specific to Pennsylvania. For this reason, the Commission will continue to explore how best to structure and apply the TRC Test for Pennsylvania.[[16]](#footnote-17) In preparation of this Final Order, the Commission and the Phase III SWE[[17]](#footnote-18) reviewed new industry literature on benefit cost analysis, such as the National Standard Practice Manual,[[18]](#footnote-19) to refine the TRC Test to meet Pennsylvania policy objectives. The 2021 TRC Test adopted herein is intended to be applicable throughout the course of Phase IV, if implemented, potentially concluding May 31, 2026. However, many issues involved in EE&C plans, program implementation, and operation of the TRC Test are ongoing in nature, and future updates may be proposed by stakeholders or the Commission as needed.

On September 19, 2019, the 2019 TRC Test Tentative Order was entered and served on stakeholders. It set forth a proposed 2021 TRC Test for Phase IV of Act 129. Notice of the 2021 TRC Test Tentative Order and the comment/reply comments periods was published in the *Pennsylvania Bulletin* on October 12, 2019, at 49 *Pa. B.* 6038. Stakeholders were encouraged to provide input on the proposed 2021 TRC Test through the formal comment and reply comment process. This Final Order summarizes stakeholder comments and issues final dispositions on all aspects of the 2021 TRC Test for Phase IV.

Comments in response to the 2021 TRC Test Tentative Order were due November 1, 2019. The following parties filed comments: Advanced Energy Management Alliance (AEMA)[[19]](#footnote-20); Duquesne Light Company (Duquesne); Energy Association of Pennsylvania (EAP); Green and Healthy Homes Initiative, Housing Alliance of Pennsylvania, Keystone Energy Efficiency Alliance, Natural Resources Defense Council, National Housing Trust, Pennsylvania Utility Law Project, and Regional Housing Legal Services (collectively, the Pennsylvania Energy Efficiency for All Coalition (PA-EEFA)); Keystone Energy Efficiency Alliance (KEEA); the Met-Ed Industrial Users Group, the Penelec Industrial Customer Alliance, the Philadelphia Area Industrial Energy Users Group, the PP&L Industrial Customer Alliance, the West Penn Power Industrial Intervenors, and the Pennsylvania Energy Consumer Alliance (collectively, the Industrials)[[20]](#footnote-21); Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company (collectively, FirstEnergy); Office of Consumer Advocate (OCA); Office of Small Business Advocate (OSBA); PennFuture, the Pennsylvania Chapter of the Sierra Club, the Clean Air Council, the Natural Resources Defense Council, the Building Performance Association (BPA), and the Philadelphia Solar Energy Association (collectively, Joint Intervenors); PECO Energy Company (PECO); and PPL Electric Utilities Corporation (PPL). Comments from AEMA and the Industrials were filed late but still considered.

Reply Comments were due November 12, 2019. The following parties timely filed reply comments: BPA;[[21]](#footnote-22) Duquesne; EAP; the Industrials; FirstEnergy; OCA; OSBA; PECO; and PPL.

On November 19, 2019, EAP filed an Answer to the Industrial’s Petition to late-file comments. On November 21, 2019, by Secretarial Letter, the Commission accepted the late-filed comments of AEMA and the Industrials and specified that parties had until 4:00 PM on November 22, 2019,[[22]](#footnote-23) to reply to the late-filed comments of AEMA and the Industrials. EAP filed additional reply comments on November 22, 2019. Duquesne filed supplemental reply comments on November 22, 2019.

## General Issues

### TRC Test Assumptions in Other Matters

 The TRC Test requires EDCs to make numerous financial and technical assumptions about the costs of operating an electric power system, future market structures, and the time-value of money. Consistent with our determination in prior TRC Test Orders, the Commission proposed in the 2021 TRC Test Tentative Order to maintain the provision that TRC Test assumptions are used exclusively for Act 129 related matters. TRC Test assumptions are not to be presumed to be binding in other regulatory matters such as prudence, cost-of-service, or other inquiries. If there are significant differences between the assumptions used in the TRC Test and the assumptions or facts at issue in such other proceedings, parties may inquire into the validity and underlying rationale of the differences in EE&C plan proceedings.

#### Comments

OSBA states that it encourages the Commission to be consistent in its decision-making, particularly with respect to how avoided costs should be developed for matters of utility regulation. OSBA comments that assumptions for avoided and incremental costs between EE&C programs and system expansion issues should be treated as two sides of the same coin. OSBA Comments at 2.

The Industrials agree that the TRC Test should apply only to the EE&C plans and not to other regulatory matters, but that this decision should not prevent the PUC from reaching similar conclusions for those specific matters based on the evidentiary records for those types of proceedings. Industrials Comments at 4.

OSBA’s broader remarks about the EE&C plans of natural gas distribution companies (NGDCs) do not fit into a specific category of the 2021 TRC Test Tentative Order. OSBA states that the Commission did not establish a methodology for the avoided cost of delivered natural gas for NGDCs who administer EE&C plans, but that such standards are necessary because the Commission should ensure that the method for deriving avoided and incremental costs of natural gas should be similar among all plans that value these avoided costs, including EDC EE&C plans, NGDC EE&C plans, and EDC plans encouraging CHP projects. OSBA highlights inconsistencies between the proposed methodology and the methodologies used in the Commission-approved NGDC EE&C plans and recommends that the Commission resolve these inconsistencies by directing the Phase III SWE to develop a methodology for calculating the avoided, delivered natural gas costs for both winter season and year-round applications for use in NGDC and EDC EE&C programs. OSBA Comments at 1-6.

#### Disposition

OSBA raises a valid point about methodological differences between the Commission’s perspective on the avoided cost of natural gas in the 2021 TRC Test Tentative Order and the calculation of these benefit streams in the EE&C plans filed by NGDCs. The Commission agrees that consistency across EE&C plans filed by different utilities that ultimately serve Pennsylvania customers is desirable. However, there are several key distinctions between EDC EE&C plans and NGDC EE&C plans.[[23]](#footnote-24) Most notably, there are no statutory requirements for NGDCs to achieve specific savings targets.

Natural gas EE&C plans are voluntary initiatives proposed by NGDCs subject to support by their ratepayers and stakeholders. Because of the lack of statutory targets and compliance penalties, the Commission has been far less prescriptive with natural gas EE&C plan inputs and assumptions than electric EE&C plans. In preparation of the 2021 TRC Test Tentative Order, we considered the issue of natural gas impacts more carefully than in prior TRC Orders when only natural gas increases were monetized in the TRC Test. Our consideration of future NGDC EE&C plans will be informed by the research and analysis conducted in preparation of this 2021 TRC Test Final Order.

We reject OSBA’s recommendation to have the Phase III SWE develop a methodology for calculating the avoided, delivered natural gas costs for both winter season and year-round applications for use in both NGDC and EDC EE&C programs for two reasons. First, the SWE budget is funded by the EDCs so the scope of work must be limited to matters that directly impact Act 129 electric programs. Second, natural gas impacts are a secondary benefit for Act 129 electric programs, but the primary benefit for NGDC EE&C plans. It follows that the level of rigor and granularity used for avoided costs may be different. Similarly, we would accept certain simplifying assumptions in a NGDC’s avoided cost of electricity forecast for measures that happen to also save electric energy that would not be acceptable in an electric EE&C plan.

For Phase IV, the Commission maintains the provision that EDCs and other parties are not bound by the TRC Test assumptions in prudence, cost-of-service, or other inquiries.

### Frequency of Review of the TRC Test

Consistent with our determination in the 2016 TRC Test Order, the Commission proposed in the 2021 TRC Test Tentative Order, to maintain the provision that the 2021 TRC Test apply for the entirety of Phase IV. This would promote consistency across the Market Potential Studies, EE&C plan development, and annual benefit-cost reporting during the entire phase. The Commission recognizes that this 2021 TRC Test is being developed almost two years prior to the beginning of a potential Phase IV, and it is possible that new issues will arise that were not considered in this Order. Consequently, we proposed to reserve the right to update or modify the 2021 TRC Test during a potential Phase IV or to direct the Phase IV SWE to develop guidance memos on such topics to promote consistency across EDCs and TRC Test results that are in line with Act 129 and the policy objectives of the Commonwealth.

#### Comments

FirstEnergy recommends that the Commission maintain that the provisions of the 2021 TRC Test apply for the entirety of Phase IV. FirstEnergy states that changing the 2021 TRC Test assumptions or methodologies mid-phase would be expected to inappropriately lead to inconsistent TRC Test results versus those used in the market potential study and EDCs’ EE&C plans. The effect of this result is the potential undermining of EDCs’ approved EE&C plans. FirstEnergy states that, in the alternative, if the Commission desires different TRC Test results due to new issues that were not considered in developing the 2021 TRC Test, such results should be presented in addition to those following the Commission directives in the 2021 TRC Test Final Order. FirstEnergy Comments at 2.

The Industrials agree that the 2021 TRC Test methodology should remain in place for the entirety of Phase IV, unless there are material changes to the energy markets that warrant revisiting the 2021 TRC Test, but that TRC Test energy and capacity market price results should be updated to reflect annual changes in wholesale market prices. Industrials Comments at 5.

OSBA agrees with the Commission’s desire to promote consistency across EDCs and TRC Test results that are in line with the policy objectives of the Commonwealth, and comments that such a policy should extend to (a) consistent treatment of EDC and NGDC EE&C plans; and (b) the quantification of avoided costs across different regulatory policies. OSBA Comments at 6.

The Joint Intervenors request that the Commission require annual updates to the TRC Test and also the 2021 TRM in order to keep up with rapid changes in the private marketplace, and that by selecting a four- or five-year update cycle, the Commission is choosing to base its policy decisions upon outdated technology and potentially outdated data collection systems related to building sciences. Joint Intervenors Comments at 6.

In reply comments, the Industrials reaffirm the importance of using actual market prices in the TRC Test and that it is preferable to modify the EE&C Plans mid-phase rather than allowing a plan based on flawed assumptions to continue for up to five years. The Industrials also state that the TRC Test results could be presented in multiple formats using the “as filed” and updated TRC Test, as FirstEnergy suggests as an alternative. Industrials Reply Comments at 4-5.

In additional reply comments, EAP opposes the suggestion by the Industrials that TRC Test market prices be updated annually using actual market conditions. EAP avers that the Industrials’ suggestion would (1) result in shifting compliance targets for the EDCs subject to Act 129, (2) increase uncertainty and complexity of Act 129 where EDCs are mandated to achieve compliance targets under threat of large monetary penalties, and (3) lead to inconsistent TRC Test results versus the TRC Test results used consistent with Commission directives at the time EE&C plans were approved by the Commission. EAP Additional Reply Comments at 2.

In supplemental reply comments, Duquesne also opposes the Industrials’ suggestion that TRC Test market prices be updated annually using actual market conditions. Duquesne Supplemental Reply Comments at 4.

#### Disposition

The Commission disagrees with the Joint Intervenors that annual updates to the 2021 TRC Test are necessary for Act 129 programs to keep pace with a rapidly evolving marketplace of energy services and technologies. We view the TRC Test as a framework for calculating the costs and benefits of EE&C programs that is agnostic to the specific technologies or conservation measures implemented. EDCs and their CSPs have the flexibility within the EE&C plan process to offer rebates for new technologies or pilot innovative data collection methods as the need arises within a phase.

We agree with FirstEnergy regarding the importance of consistency between annual cost-effectiveness reporting, EDC EE&C plans, and the market potential studies. This determination is at odds with the Industrials’ suggestion that the avoided costs used to calculate TRC benefits be updated on an annual basis. An annual update to the avoided costs forecast could cause EE&C programs or measures to be cost-effective one year and not cost-effective the next year based on market fluctuations. Because EE&C measures can have lives up to 15 years, the avoided costs forecast is inherently a long-term projection. Frequent updates to the projections could create inconsistent signals in the market to EDC planners and CSPs.

The Commission has considered the positions of the parties and concludes that that the 2021 TRC Test methodology shall apply for the entirety of Phase IV. Amending the TRC Test methodology mid-phase could result in extensive EE&C plan changes and potential reconsideration of EDC targets. Such changes would also interfere with year-to-year comparisons within a phase. In addition, it is important to be able to compare an EDC’s performance against its EE&C plan using a common definition of TRC costs and benefits. However, as discussed in Section B.1, Vintage of Avoided Cost Forecasts, the Commission sees the value in periodically comparing avoided costs projections to market prices for informational purposes.

### Level at Which to Calculate and Report TRC Test Results

In the 2021 TRC Test Tentative Order, consistent with our determination in the 2016 TRC Test Order which provided that “compliance will be measured separately going forward in any phase for which there will be DR or EE goals,” the Commission proposed to determine cost-effectiveness separately for EE and DR at the EE&C plan level. *See 2016 TRC Test Order* at 18. Within the broad categories of EE and DR, the determination of cost-effectiveness occurs at the EE&C plan level. EDCs are required to develop and implement a portfolio of programs with benefits that are greater than the costs. TRC testing at the plan level gives new programs and technologies adequate opportunity to establish whether they can contribute to the EE and DR goals of Act 129.

As in prior phases, the Commission proposed in the 2021 TRC Test Tentative Order to continue applying the TRC Test at the plan level and to continue to reserve the right to reject any program with a low TRC test ratio. EDCs are required to estimate and report program-level TRC test ratios in their EE&C plans and in each final annual report. TRC test ratios must also be reported for the EE and DR portfolios as well as the entire EE&C plan (inclusive of both EE and DR).

#### Comments

The Industrials support the separate evaluation of EE and DR TRC results, but request that the TRC Test be applied on a measure basis, rather than a total plan basis as proposed. The Industrials state that is not in the public interest to continue measures that do not meet the TRC cost-effectiveness standard, and furthermore request that if no measures for a class show a positive TRC, then the next phase should not include that class. Industrials Comments at 5-7.

OSBA does not object to evaluating TRC Test compliance for EDC EE&C plans at a plan level and supports requiring EDCs to report TRC Test results at the program level. OSBA further recommends that, in considering whether it should reject any program with a low TRC test ratio, the Commission should also consider whether the cross-subsidies to program participants are excessive. OSBA also requests that the Commission consider whether the 2021 TRC Test should be applied at the program level for NGDC EE&C programs. OSBA Comments at 7.

PA-EEFA supports the Commission’s proposal to continue applying the TRC Test at the plan level. PA-EEFA Comments at 3.

In additional reply comments, EAP asks the Commission to reject the Industrials’ suggestion that cost-effectiveness be evaluated at the measure level or customer class level. EAP Additional Reply Comments at 2.

In supplemental reply comments, Duquesne avers that the Industrials’ recommendation that cost-effectiveness be evaluated at the measure level or customer class level appears to conflict with Act 129. Duquesne points out that Act 129 requires analysis of the cost and benefit of each Plan submitted and that EE&C Plans provide a diverse cross section of alternatives for customers of all rate classes. Duquesne further asserts that efficiency programs can stimulate early adoption of emerging technologies that may not currently be cost-effective. However, as economies of scale grow, product costs decrease, thus making them cost-effective over time. Duquesne Supplemental Reply Comments at 2.

#### Disposition

The Commission disagrees with the measure-level TRC Test screening assumption suggested by the Industrials. It is important for EDCs to be able to offer comprehensive programs that address a suite of energy needs within a participating facility. Screening cost-effectiveness at the measure level could lead to adverse outcomes where EDCs are forced to limit the scope of efficiency projects within homes and businesses based on assumptions about avoided costs and incremental measure costs that each carry a degree of uncertainty.

We agree with the Industrials’ position that consideration of cost effectiveness by customer class is important. We have directed the Phase III SWE to present Phase IV Market Potential Study (MPS) results separately for the Residential, Residential Low Income, Small Commercial & Industrial (C&I), and Large C&I sectors so that goal setting can consider the remaining EE/DR potential – and the cost to acquire it by class. However, we maintain that EDCs need to have the flexibility to design their EE&C plans in a way that works for them and their stakeholders given the significant compliance penalties in place for Act 129 programs. We agree that cross-subsidies are an adverse outcome that EDC EE&C plans should consider but conclude that this 2021 TRC Test Final Order is not the appropriate forum to issue detailed guidance on the topic.

Therefore, the determination of cost effectiveness for Phase IV of Act 129 will remain at the EE portfolio and DR portfolio level. EDCs are not required to report TRC test ratios at the customer class level, however, they will be required to continue to estimate and report program-level TRC test ratios in their EE&C plans and in each final annual report. We also note that this 2021 TRC Test Final Order does not pertain to NGDC EE&C plans and that the Commission’s determination applies exclusively to Act 129 Phase IV.

### Discount Rate

A discount rate is the percentage used to calculate the present value of future costs and benefits. Discounting reflects the reality that, all else equal, people prefer benefits now rather than later, and vice versa for costs. When choosing a discount rate, it is important to consider whose preferences are to be reflected by the discount rate. In the case of energy efficiency programs and other public policy, the discount rate is typically selected to reflect the preferences of the public at large. Because Act 129 is an energy efficiency and conservation program, we proposed in the 2021 TRC Test Tentative Order to use the discount rate that reflects the preferences of the public at large.

We proposed to establish a discount rate of 3% in real terms or 5% in nominal terms for Pennsylvania’s EE&C programs in Phase IV. The difference between the real discount rate and nominal discount rate is the assumed rate of inflation. We further proposed a standard 2% inflation assumption be used by all EDCs for Phase IV, based on the projections of the United States (US) Congressional Budget Office’s (CBO’s) 2019 to 2029 Budget and Economic Outlook.[[24]](#footnote-25) Proposing these percentages is a change from prior TRC Tests.

Act 129 of 2008 did not set discount rates. We discussed setting discount rates in prior TRC Test orders but did not set specific rates. The 2009 TRC Test Order,[[25]](#footnote-26) for example, discussed the appropriate discount rate for Act 129 programs:

[U]sing an EDC’s weighted average cost of capital (WACC) may cause some energy efficiency programs to be undervalued and that the appropriate discount rate requires further consideration. Because of the short time period to complete this [2009 TRC] Order, for the first year of TRC testing, we shall, nonetheless, use the EDC’s post-tax WACC as the discount rate… Our decision to take this approach for the first year will not, however, be controlling for future years.

Although the 2009 TRC Test Order characterized the discount rate as a topic for further consideration, subsequent TRC Test Orders only included limited discussion. The 2013 TRC Test Order[[26]](#footnote-27) simply stated that the “discount rate for the [2013] Pennsylvania TRC Test is the EDC’s weighted average cost of capital.” The 2016 TRC Test Order[[27]](#footnote-28) noted the following, in a discussion of whether a different discount rate might be appropriate for Combined Heat and Power (CHP) projects:

The EDC’s weighted average cost of capital is the correct basis for the discount rate so that supply-side and demand-side alternatives are placed on a level playing field. Accordingly, EDCs shall continue to use the EDC’s weighted average cost of capital as the discount rate used in TRC calculations for all measures and programs that are eligible for Act 129 funding.

For Phase IV, the Phase III SWE provided staff with further research and evaluation regarding discount rates. According to the Phase III SWE, three key findings support the decision to use a 3% real discount rate for the 2021 TRC Test. First, economic theory of benefit-cost analysis indicates that long-term gross domestic product (GDP) growth rates can be used as a rough proxy for the public’s preference for tradeoffs over time. In the United States, real GDP growth has averaged 3.22% since 1947, according to the US Bureau of Economic Analysis.[[28]](#footnote-29) Second, the US Office of Management and Budget endorses a 3% real discount rate when policies intend to assess the public’s preference for tradeoffs over time,[[29]](#footnote-30) as is the case here. Finally, this additional research also indicated that a 3% real discount rate would be consistent with the discount rates that have been used for energy efficiency programs in other jurisdictions.[[30]](#footnote-31)

#### Comments

The Industrials support the refinement of the discount rate and state that a clearly defined discount rate for use by all EDCs reflecting the interest rate the consumer could be paying if they had to finance an energy efficiency investment provides a more accurate calculation. Industrials Comments at 7.

KEEA supports the Commission’s proposed discount rate, asserting that it more accurately represents the net present value of future savings than the weighted average cost of capital. KEEA Comments at 2.

PA-EEFA agrees with the Commission’s justification for and use of a 3% real discount rate. PA-EEFA Comments at 3.

OSBA agrees that the utility’s weighted average cost of capital has little relevance for evaluating EE&C programs but states that the Commission should adopt a discount rate for EE&C programs based on the pre-tax cost of capital for the customers who benefit from and provide financing for such programs rather than a social policy discount rate. OSBA Comments at 7-9.

In reply comments, the Industrials concur with OSBA’s general goal to ensure that the 2021 TRC Test assumptions accurately reflect the costs incurred by consumers to implement measures. If OSBA’s proposal provides a more accurate result, the Industrials support adopting OSBA’s proposal. Industrials Reply Comments at 6.

In supplemental reply comments, Duquesne disagrees with the proposed discount rate because (1) a utility’s WACC is typically lower than a consumer’s finance rate and (2) demand side management programs are considered long-term utility infrastructure investments. Duquesne asserts that the utility’s WACC is therefore a more appropriate discount rate. Duquesne Supplemental Reply Comments at 5.

#### Disposition

Stakeholders were generally supportive of our proposal to disassociate the Act 129 discount rate from an EDC’s WACC. Our proposal of a 3% real discount rate (5% nominal discount rate) is lower than EDC WACC values used in prior phases of Act 129. PA-EEFA and KEEA supported the direction and rationale for the change. Although neither the Industrials nor OSBA recommend a specific Act 129 discount rate, they aver that a rate higher than an EDC’s WACC would be appropriate.

Contrary to OSBA’s suggestion, Act 129 programs are, in fact, a government policy designed to encourage investments in energy efficiency that would not happen absent policy intervention. Accordingly, the 3% real discount rate will be used for Phase IV of Act 129.

### Effective Useful Life

As established in Act 129 and as discussed in prior TRC Test Orders, any given measure is limited to a maximum of 15 years of savings benefits. 66 Pa. C.S. § 2806.1(m). Measures with recurring costs, such as increased natural gas consumption for CHP projects, are also limited to 15 years of negative benefits. Typically, the costs of energy efficiency are front-loaded, and the benefits accrue over many years. The National Standard Practice Manual (NSPM) addresses the issue imposed by capped measure life assumptions as “end effects”[[31]](#footnote-32) and suggests a methodology whereby costs are reduced proportionately to truncated lifetime benefits. The position of the Commission is that end effects adjustments such as the ones proposed in the NSPM are not acceptable for use in Phase IV. While certain technologies may have an expected useful life greater than 15 years, Act 129 is clear about the 15-year limit, and any adjustment to the cost ledger would circumvent the legislative directive. Therefore, we saw no reason to propose any changes for this provision.

For some EE&C measures, a single baseline may not be appropriate for the duration of the mechanical life of the equipment. Although compliance is based on “first-year” savings, lifetime savings are required for the calculation of TRC benefits. Dual baselines are appropriate when a known change in codes and standards lowers the savings opportunity in future years or the baseline equipment that served as the baseline initially reaches the end of its useful life and a code-minimum baseline needs to be assumed for the remainder of the measure life. Thus, for the 2021 TRC Test, the Commission proposed that EDCs and their evaluation contractors continue to use dual baselines where appropriate and practical. For example, if a change in standards were expected to take effect in 2024, the change would occur during the measure life of a measure installed in 2022, and a dual baseline would be required. If there were no proposed or expected changes, no dual baseline would be necessary. Dual baselines address known code changes that are on the horizon.

#### Comments

The Industrials support the Commission’s plan to continue using a 15-year maximum for the purposes of calculating the benefit/cost analysis, even if a technology could exceed that 15-year maximum. The Industrials request clarification as to which 15‑years of avoided costs should be used in this analysis and suggest that the 15-year avoided cost stream for each program year should begin with the calendar year at the close of the program year when the project is completed. Industrials Comments at 7-8.

KEEA and PA-EEFA both request that the Commission adjust costs for energy efficiency measures limited by the 15-year cap, such that the 2021 TRC Test would not include only 15 years of benefits but rather the full lifetime costs. KEEA Comments at 2. Additionally, PA-EEFA supports continued application of dual baselines where appropriate and practical so that measure savings are calculated appropriately. PA-EEFA Comments at 3-5.

In reply comments, the Industrials agree with KEEA and PA-EEFA that ongoing costs beyond the initial 15 years that the measure is in use should be excluded from the 2021 TRC Test but state that upfront costs should be classified as being paid in full during year 1 of the measure life. Industrials Reply Comments at 8-9.

#### Disposition

As discussed in Section B.2, Avoided Cost of Electric Energy, the Industrials are correct that the avoided cost streams for a given Act 129 program year are mapped to the calendar year at the close of the program. Therefore, in the “Outputs” tab of the Avoided Cost Calculator, Act 129 Program Year 13 (June 1, 2021 to May 31, 2022) is associated with the “2022” avoided cost array.

While we acknowledge the limitations created by the 15-year measure life cap, we disagree with the suggestion of KEEA and PA-EEFA that our interpretation of the statute is too narrow. The objective of the statute is clear, and we will not permit the reduction of TRC costs in Phase IV to counteract the intent of the Legislature on this issue. Regarding how measure costs are accounted for in relation to a measure with a life that exceeds 15 years, we agree with the Industrials[[32]](#footnote-33) and clarify that, consistent with Act 129 and current practice, the up-front costs will not be pro-rated and will be classified as incurred in full during Year 1 of the measure for Phase IV.  We further clarify that, as is the current practice, on-going costs related to an installed measure that are estimated to occur up to and including Year 15, adjusted to NPV, will also be included in the TRC Test calculation for Phase IV.  Finally, we clarify that, as is the current practice, estimated on-going costs that occur beyond 15 years will continue to be excluded for Phase IV.

### Low-Income Programs

We did not propose any changes or special reporting requirements for low-income programs. Like any other EE&C program, low-income programs are not required to have a TRC Test ratio greater than 1.0. If an EDC has multiple low-income programs, there is no need to aggregate the cost-effectiveness results across low-income programs for reporting purposes.

#### Comments

As discussed in the comments of Section A.3.a, Level at Which to Calculate and Report TRC Test Results, above, the Industrials comment that if a measure does not have a TRC value greater than 1.0, then the measure should be modified or terminated, and that low-income programs should produce a TRC value greater than 1.0. Industrials Comments at 8.

As discussed in the comments of Section A.3.a, Level at Which to Calculate and Report TRC Test Results, above, OSBA recommends that, in considering whether it should reject any program with a low TRC test ratio, the Commission should consider whether the cross-subsidies to program participants are excessive, because programs that have a low TRC test ratio will generally require higher subsidies in order to induce customer participation. OSBA Comments at 7.

In reply comments, the Industrials point to OSBA’s argument about cross-subsidies as an additional reason to apply the TRC Test at the measure level. Industrials Reply Comments at 6-7.

In reply comments, OCA notes that Act 129 specifically carves out the need for the inclusion of low-income customer programs in EE&C plans and specifically defines the total resource cost on a plan, not measure level, and that low-income customer programs should be maintained. OCA Reply Comments at 3-4.

In supplemental reply comments, Duquesne opposes the Industrials’ recommendation to apply measure level TRC screening to low-income measures as it conflicts with Act 129 and risks eliminating EE improvements from benefitting the most vulnerable customers. Duquesne Supplemental Reply Comments at 3.

#### Disposition

The Commission disagrees with the Industrials’ position that all measures should be required to have a TRC ratio of greater than or equal to 1.0 and agrees with OCA that low-income programs should be continued. Low-income programs are an important example of why we have established the Act 129 cost-effectiveness requirement at the plan level as opposed to the program or measure level. Often, low-income programs need to rely on a direct installation program delivery model, which increases the administrative cost and lowers cost-effectiveness. Additionally, CSPs delivering low-income programs will encounter health and safety issues that must be addressed as part of the job. Addressing health and safety issues costs program dollars but generates no TRC benefits. If low-income programs were required to be cost-effective, a likely outcome is that low-income households would be underserved by Act 129 residential programs despite funding them via rate recovery. This would be a regressive policy, given that energy costs make up a larger share of low-income household budgets than they do for market rate residential households.

Phase IV of Act 129 will continue to have no cost-effectiveness requirement for any program or measure, low-income or otherwise. However, the Commission recognizes OSBA’s point about cross subsidies. The Commission will carefully weigh this issue when considering any low-income carve outs in the potential Phase IV Implementation Order. OSBA and other stakeholders are encouraged to comment on the equity and any cross-subsidy concerns in that proceeding or in the EE&C plan review for any EDC with a Phase IV mandate.

### Basis of TRC Test Impacts

In the 2021 TRC Test Tentative Order, the Commission proposed to continue the process established in Phase III, where EDCs are required to report verified gross savings, verified net savings, and actual costs in their final annual reports. *See 2016 TRC Test Order* at 46. Thus, compliance would continue to be based on “verified gross” kWh and kW electric savings, and costs would continue to be based on “actual” costs. Because EDCs use net savings for planning purposes, they would continue to report net savings for each program and the total portfolio of programs as well as describe how such net savings are calculated. In addition, EDCs would continue to report TRC test ratios in EE&C plans in two ways: (1) based on projected gross savings and (2) based on projected net savings. Actual costs are not known at the time of EE&C plan submission, so all cost values would be projected.

#### Comments

The Industrials request that the reporting process be modified to add an analysis comparing the projected avoided electricity costs to actual avoided electricity costs, and state that claims about the actual costs and benefits of the EE&C plans should be based on actual market prices, rather than the projections made prior to the beginning of the phase. Industrials Comments at 8-9.

In supplemental reply comments, Duquesne disagrees with the Industrials’ recommendation of comparing projected avoided costs with actual avoided costs as it would increase uncertainty and complicate the calculation of annual avoided cost updates. Duquesne Supplemental Reply Comments at 4.

#### Disposition

The Industrials’ comment about using actual market prices to calculate TRC benefits rather than a forecast developed concurrently with the EE&C plan is discussed at length in Section B.1, Vintage of Avoided Cost Forecasts, of this Order. The Commission disagrees with the Industrials that actual experienced market prices should be used in annual benefit cost reporting. Act 129 measure lives can be 15 years long and actual market prices cannot be known in the future. Therefore, even if avoided cost forecasts were updated annually, the TRC Test results for a program, project, or measure would rely on 14 years of projected prices and one year of actual prices. Investments in energy efficiency are undertaken based on assumptions of future energy costs so there is value in comparing the projected lifetime benefits of a program, project, or measure to forecasts available at the time of the investment.

Therefore, EDCs will continue to report verified gross savings, verified net savings and actual costs in their final reports. Compliance will continue to be based on “verified gross” kWh and kW electric savings, and costs will continue to be based on “actual” costs.

### Measures Supported by Both Act 129 Programs and Other Funding Streams

The Commission did not propose any changes regarding this issue from its position established in prior TRC Test Orders. Outside incentives, whether they are rebates or tax credits, reduce the participating customers’ costs; therefore, the reduction must be reflected in lower incremental measure costs (IMCs) and be factored into an EDC’s TRC Test calculation. The Commission recognized that tracking non-Act 129 incentives paid to EDC customers may be difficult as some customers may not be inclined to provide the requested information or may not have access to it. Consistent with prior TRC Test Orders, the Commission proposed in the 2021 TRC Test Tentative Order that EDCs only need to factor in, as reductions to cost, the non‑Act 129 incentives that are reasonably quantifiable by the EDC at the time the Act 129 transaction is recorded. EDCs would continue to include the full benefits determined by the gross verified calculations of the TRC Test for measures that include incentives from non-Act 129 funding sources if any portion of the measure is attributable to Act 129. The availability of non-Act 129 funding streams for a measure may increase the estimates of free ridership, which would reduce benefits in the net verified calculations for the measure. *See 2013 TRC Test Order* at 21.

#### Comments

The Industrials support the Commission’s determination to continue the consideration of known outside incentives into the TRC Test. Industrials Comments at 9.

OSBA avers that the costs used in the TRC Test should be total costs, with no deduction for alternative revenue streams, so as to not encourage utilities to include economically inefficient programs in the EE&C plans simply because the costs may be borne by parties other than the participant and the utility ratepayers. OSBA states that the availability of other funding streams should be recognized by utilities and taken into consideration in developing the need for participant subsidies, but that the objective of the TRC Test should be to compare the overall savings of a particular efficiency measure with the cost of that measure, regardless of which party bears the costs of the measure. OSBA Comments at 9.

In reply comments, FirstEnergy avers that excluding alternative revenue streams, including tax credits, is at odds with long-standing standard industry practices and that OSBA’s recommendation to exclude tax credits should be rejected. FirstEnergy Reply Comments at 2.

#### Disposition

We disagree with OSBA’s assertion that incentives from outside of Act 129 should be ignored for purposes of the 2021 TRC Test. As stated in the TRC TEST EXPLAINED section of this Order, “[i]n Pennsylvania, the TRC Test considers the combined effects of an EDC’s EE&C plan on both participating and non-participating customers based on the costs incurred by both the EDC and any participating customers.” While participating customers are presumably taxpayers, OSBA’s suggestion to expand the sphere of consideration more broadly is inconsistent with the TRC Test perspective and adopts a key feature of the Societal Test. The California Standard Practice Manual includes a useful discussion of the five issues that differ between the TRC Test and Societal Test. “Second, tax credits are treated as a transfer payment in the Societal Test, and thus left out*.*”[[33]](#footnote-34) The Commission agrees with FirstEnergy’s reply comment and rejects OSBA’s recommendation. Therefore, reasonably quantifiable outside incentives will be treated as a reduction in incremental cost for Phase IV of Act 129.

## Avoided Costs of Supplying Electricity

In the 2021 TRC Test Tentative Order, the Commission proposed continued use of the *status quo* Act 129 methodology to develop forecasted avoided costs of electricity, with slight modifications. The intention was that more detailed instructions would improve consistency across EDCs and lead to better alignment with market conditions. To meet this objective, the Phase III SWE developed a new MS-Excel spreadsheet Order. The calculation model (Avoided Costs Calculator or ACC) to implement the methodology outlined in the 2021 TRC Test Tentative Commission proposed that EDCs must use this standard tool when developing avoided costs for Phase IV. The ACC is located on the Commission’s website at: <http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/total_resource_cost_test.aspx>.

The following paragraphs were topics of proposed changes and topics of continuation from prior TRC Test Orders as they relate to avoided costs of supplying electricity.

### Vintage of Avoided Cost Forecasts

In the 2021 TRC Test Tentative Order, the Commission proposed that EDCs would continue to develop a single forecast of avoided costs for use in Phase IV EE&C plans and all cost-effectiveness reporting in the annual reports. For simplicity in compliance, EDCs would not be expected to update avoided costs mid-phase. The Commission reserved the right to require updating and proposed that EDCs could request updating depending on market changes.

#### Comments

The Industrials comment that EDCs should use actual experienced market prices in annual and phase reporting, and that all stakeholders should have an equal ability to petition the Commission if market conditions change. Industrials Comments at 10-11.

PA-EEFA recommends that the Commission direct the SWE to annually consider whether there are indications that market conditions have varied sufficiently to warrant an update or modification of the avoided costs and to inform the Commission of its findings. PA-EEFA Comments at 5.

#### Disposition

As previously stated in section A.7.b., Basis of TRC Test Impacts, the Commission disagrees with the Industrials that actual experienced market prices should be used in annual benefit cost reporting because of the length of Act 129 measure lives, the fact that actual market prices cannot be known in the future, and the assumptions of future energy costs that motivate decisions to undertake energy efficiency measures at the time of investment.

While we maintain the position that a single forecast of avoided costs should be the foundation of Phase IV EE&C plans and annual reports, we agree with PA-EEFA that there is value in periodically assessing the accuracy of the forecast. Consequently, we will direct the Phase IV SWE to include in its Final Annual Reports a comparison of forecasted avoided costs of electricity to load weighted real time locational marginal prices (LMPs) for each EDC service area. In preparation for the 2021 TRC Test Tentative Order, the Phase III SWE calculated load weighted market prices by EDC and costing period and compared them to the avoided costs forecasts developed by each EDC in 2015 as part of their Phase III EE&C plan filings. This comparison revealed a high degree of alignment between forecasts and actual costs. The Phase III SWE’s investigations of differences helped inform our thinking about standardizing certain aspects of the avoided costs of electric energy methodology across EDCs and the development of the ACC.

If this assessment reveals limited variation between projections and actual market prices, the findings should assuage concerns raised by the Industrials. Should significant differences between the Phase IV avoided costs forecast and actual experienced market prices be found, the Commission may reconsider the appropriateness of a static forecast of avoided costs or make changes in the methodology used to develop the avoided costs forecast. The Commission reserves the right to require a mid-phase update to avoided costs forecasts should the variance between EE&C plan projection and current market conditions become large enough to fundamentally alter the benefit/cost results at the portfolio level.

### Avoided Cost of Electric Energy

In the 2021 TRC Test Tentative Order, the Commission proposed to continue to use a 20-year period. The proposed modification in methodology entailed the calculations for avoided electricity energy costs. The period would be dissected into three segments, as discussed below. The 2021 TRC Test Tentative Order proposed that forecasted avoided energy costs would continue to be calculated in a time-differentiated format, but proposed to change from four to six distinct periods per annum, as defined in the 2021 TRM at Table 1-3,[[34]](#footnote-35) and illustrated as follows:

**The first segment – years one through four**:The proposed methodology for segment one (calendar years 2022 through 2025) would use NYMEX[[35]](#footnote-36) PJM electricity futures prices for on-peak and off-peak periods as a basis. The Commission proposed that EDCs use market-based electricity prices whenever possible. Under the proposal, NYMEX futures prices would be obtained at the PJM Interconnection Western Hub location with an EDC zonal basis adjustment based on the *2019 PJM State of the Market Report, Chapter 11*.[[36]](#footnote-37) The zonal adjustment factor would continue to be defined as the ratio of zone-specific real-time load-weighted average LMP against the Western Hub real-time load-weighted average for years 2018 and 2019. The same zonal adjustment would continue to be used for both on-peak and off-peak price periods.

In the 2016 TRC Test Order, we permitted the EDCs to use NYMEX PJM futures for the specific zone. However, in the 2021 TRC Test Tentative Order, the Commission proposed to disallow this for Phase IV due to inconsistent and incomplete futures price data at the zonal level. In addition, we proposed that the prompt month for NYMEX PJM electricity futures be established as three months prior to the EE&C plan filing date.[[37]](#footnote-38)

**The second segment – years five through ten**:The proposed methodology for segment two (calendar years 2026 through 2031) was based on NYMEX natural gas futures converted into electricity costs. Medium-term NYMEX natural gas futures would be blended with the longer-term US Energy Information Administration’s (EIA) Annual Energy Outlook (AEO) projected natural gas costs across the segment 2 period to shift from market-based conditions to a more stable model that is public and transparent. The proposal was that natural gas costs would be converted into an electric energy price with an additional spark price spread,[[38]](#footnote-39) using the following calculation steps:

1. Collect monthly NYMEX natural gas futures at Henry Hub[[39]](#footnote-40) for years one through ten. The prompt month for NYMEX futures is established as three months prior to the EE&C plan filing date.
2. Use the differential between the Henry Hub as the source and TETCO M-3[[40]](#footnote-41) as the destination for the locational basis adjustment to the natural gas prices for utilities west of the Susquehanna River. The locational basis adjustment to the natural gas prices for utilities east of the Susquehanna River is the basis differential between the Henry Hub as the source and Transco Zone 6 non-New York[[41]](#footnote-42) as the destination. For EDCs that have service territory on both sides of the river, such as PPL Utilities and Metropolitan Edison, the location would be based where most of the electric load is present. EDC locational adjustments for the NYMEX reference natural gas price would be based on the average of locational adjustment prices in years one and two and applied to the Henry Hub NYMEX natural gas futures for years one through ten.
3. Gather annual forecasted natural gas costs from the 2020 US EIA AEO projected costs for Electric Power Users in the Mid-Atlantic region using nominal dollars. Annual AEO natural gas costs would be converted into monthly or seasonal periods that align with Table 1-3 of the 2021 TRM using adjustment factors derived from zone location adjusted NYMEX natural gas futures prices years one and two.
4. Derive final natural gas costs by blending NYMEX natural gas futures and the AEO projected natural costs over the segment two period. The Commission proposed that this would be calculated by adding one-seventh of the differential between AEO natural gas costs and locational adjusted NYMEX natural gas futures for each segment year starting in year five to the zone location adjusted NYMEX natural gas futures.
5. Convert final natural gas costs into electricity costs using assumed heat rates for the average existing natural gas generating station. Heat rates of a gas turbine would be used for on-peak periods and the heat rate of a combined cycle unit would be used for off-peak periods. The proposed heat rate for on-peak would be 7,649 BTU/kWh, and off-peak would be 11,176 BTU/kWh.[[42]](#footnote-43)
6. Add a spark spread cost to the avoided energy costs for segment 2. The spark spread would be determined as the average difference between the zone location adjusted NYMEX PJM electricity futures and zone locational adjusted electricity costs based on NYMEX natural gas futures for years one through three using the ACC.

**The third segment – years eleven through twenty**: The proposed methodology for segment three (calendar year 2032 through 2041) would be a similar methodology as for the second segment, but the Commission proposed that it be based solely on long-term AEO projected natural gas costs. Under the proposed modification, natural gas projected costs would be converted into an electric energy price using a spark price spread calculation, with the following calculation steps:

1. Gather annual forecasted natural gas costs from the 2020 US AEO projected costs for Electric Power Users in the Mid-Atlantic region using nominal dollars. Annual AEO natural gas costs would be converted into monthly or seasonal periods that align with the 2021 TRM utilizing adjustment factors derived from zone location adjusted NYMEX natural gas futures prices years one and two.
2. Convert final natural gas costs into electricity costs using the same heat rates for on-peak and off-peak periods as for the second segment.

3. Add a spark spread cost to the avoided energy costs for segment 3. The spark spread would be the same as determined in the second segment.

#### Comments

Duquesne objects to the use of six futures pricing periods and states that calculating futures prices in this way would not increase accuracy. Duquesne agrees with the proposed change to use PJM Western Hub prices in the forecast and to disallow zonal energy prices. Duquesne Comments at 2-3.

FirstEnergy and PECO point out a potential error in the language describing the heat rates to be used for on-peak and off-peak prices. They suggest that the Commission intended to apply the higher heat rate to the on-peak period, rather than to the off-peak period as in the proposed order. FirstEnergy Comments at 2-3, PECO Comments at 5.

The Industrials state that they support the revised methodology, but that EDCs should update the forecasts to actual market conditions when evaluating the cost-benefit ratio for plan performance. Industrials Comments at 11-12.

PECO makes several comments with respect to the electricity and natural gas price forecasts. First, PECO states that the use of the EIA forecast is problematic because (1) the EIA AEO projections pertain to a very broad "Middle Atlantic Region" designation that is less applicable to PECO than the NYMEX market prices; (2) the EIA AEO is updated infrequently, and may not be reflective of current market expectations; and (3) the EIA AEO is an entirely different data source than NYMEX futures, increasing the chance of internal inconsistencies in the forecast. PECO proposes using NYMEX futures data, where available, and escalating at the rate of the EIA forecast or the BLS escalation rate thereafter. PECO Comments at 2-3. Second, with regard to the proposed heat rate value, PECO requests that the Commission continue to use values from the EIA AEO to determine heat rates, rather than its new proposed method, because the proposed method relies on historic data in Form EIA-860 which represent data from 2017 and may be outdated. PECO Comments at 3-4. Lastly, PECO suggests that the proposed spark spread calculation be changed such that the spark spread simply escalates at the BLS escalation rate, rather than the Commission’s proposed approach, which would only escalate spark spreads if the magnitude of the spark spread was greater than or less than $1/MWh. PECO Comments at 4-5.

Several parties commented on different aspects of the ACC. OCA states that it supports the use of the ACC and requests that the completed calculators be included with the filed EDC EE&C plans. OCA Comments at 4. FirstEnergy and PECO describe proposed changes to the ACC and/or text of the proposed Order to ensure consistency between the Order text and ACC. FirstEnergy comments that the PJM Base Residual Auction (BRA) clearing prices entered within the ACC are not in the same reference year dollars and need to be escalated, natural gas zonal adjustments should be properly escalated, and average monthly values, should be weighted by the number of days in each month. FirstEnergy Comments at 3. PECO comments that zonal adjustments are not calculated from the correct reference years and should utilize reference years 1 and 2. Additionally, PECO requests clarification on the calendarization of avoided costs as the PJM calendar does not align with years. PECO Comments at 5.

In reply comments, the Industrials state that they urge the Commission to carefully review the suggestions of PECO, PPL, and FirstEnergy, and to consider convening a stakeholder meeting to discuss any disputes regarding the assumptions. Industrials Reply Comments at 5.

#### Disposition

The Commission disagrees with Duquesne’s opinion that use of six futures pricing periods would not increase accuracy. The characterization of unique shoulder and winter time periods is appropriate because review of NYMEX electricity futures in the winter months of December, January, and February reveals electric energy prices that are 20 to 25% higher than in shoulder months. Consequently, six time-differentiated price periods are important to properly value measures that have larger impacts in those winter periods, and for that reason six pricing periods will be used.

The Commission agrees with comments from FirstEnergy and PECO which suggest that proposed heat rates have been transposed. The proposed heat rate should be 11,176 BTU/kWh for on-peak periods and 7,649 BTU/kWh for off-peak periods for Phase IV of Act 129.

The Commission disagrees with PECO’s recommendation regarding the use of EIA AEO natural gas price forecast, as this data source has been included with prior TRC Test orders. While the Commission shares PECO’s general preference for market-based prices, the EIA AEO considers broader exogenous long-term market factors that could influence natural gas prices and therefore, is more appropriate for using natural gas price forecasts.

The Commission acknowledges and agrees with PECO’s comments that generation equipment heat rates will likely improve in the future from the 2018 source data. However, a forecast schedule of plant retirements and replacements with newer, more efficient technologies introduces uncertainty, therefore the Commission rejects PECO’s recommendation to improve the future heat rate stipulated value over time.

As PECO notes, to the extent that the established heat rates are incongruent with market conditions, the spark spread adjustment, derived from NYMEX electricity prices, largely corrects the inconsistencies. The Commission accepts PECO’s recommendation to modify the ACC so that negative spark spreads escalate in the negative direction over time. Additionally, we will direct the Phase IV SWE to study the change in generation heat rates for gas turbines and combined cycle units during Phase IV to assess whether there are material improvements in the generation fleet. If this study uncovers significant differences between the assumed static heat rates for electric generators, the Commission reserves the right to require a mid-phase update to avoided cost forecasts should the variance between EE&C plan projection and current market conditions become large enough to fundamentally alter the benefit cost results at the portfolio level.

The Commission agrees with observations from FirstEnergy and PECO which noted inconsistencies within the ACC and the 2021 TRC Test Tentative Order. The ACC was amended to address these inconsistencies. Of specific note, the ACC now utilizes inflation to escalate costs in compliance with TRC Test Order revisions within section B.5, Escalation Rate. However, the Commission disagrees with FirstEnergy comments to weigh monthly values in the last 10 years of the natural gas price forecast as this additional step adds unnecessary complexity for a minor adjustment.

The Commission agrees with OCA comments and requests that completed ACCs be included with individually filed EDC EE&C plans.

Finally, the Commission provides clarification in response to PECO’s request by repeating the commentary on the tab “General Instructions” of the ACC:

The PA Act 129 calendar follows the PJM calendar, which starts in the month of June and ends in the month of May. For a measure installed within a PA Act 129 program year, the avoided energy costs are based on the calendar year of the last months in the PJM calendar. For instance, a measure installed in PA Act 129 Program Year 13 (6/1/2021-5/31/2022), the avoided energy costs will be calculated based on 12 months of data from the calendar year 2022.”

With these changes implemented, the Commission deems it unnecessary to convene a stakeholder meeting to discuss the assumptions, as the Industrials suggested in their reply comments.

### Nominal vs. Real Dollars

In the 2021 TRC Test Tentative Order, the Commission proposed that EDC avoided cost forecasts would continue to be developed in nominal dollars (*e.g.*, the avoided cost of supplying electricity in 2030 must be expressed in 2030 dollars). A nominal discount rate is to be used to calculate the NPV of benefits in the base year (2021). Assumed inflation rate would be 2.0%, consistent with the CBO assumptions. This is a continuation of the standard practice used by the EDCs in prior phases.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

For Phase IV, the Commission directs EDCs to develop avoided costs in nominal dollars and calculate the NPV of benefits using a 2021/2022 (Act 129 Program Year 13) base year, assuming an inflation rate of 2.0%.

### Line Losses

The algorithms and assumptions in the 2021 TRM calculate energy and demand savings at the customer meter. Similarly, EDC CSPs and evaluation contractors produce savings estimates for custom projects at the meter level. When calculating TRC benefits, these resource savings must be scaled to the system level to account for losses during transmission and distribution (T&D). Table 1-4 of the 2021 TRM[[43]](#footnote-44) provides line loss factors by EDC and customer class. In the 2021 TRC Test Tentative Order, the Commission proposed that EDCs continue to use these values to calculate system-level electric energy and peak demand impacts and to determine TRC benefits.

#### Comments

PA-EEFA comments that the Commission should use marginal line losses to calculate system-level impacts, not average line losses as proposed, and notes that average line losses will understate the total savings. PA-EEFA Comments at 5-6.

#### Disposition

The Commission disagrees that marginal line losses should be used to calculate system level impacts. Line loss factors are stipulated in Table 1-4 of the 2021 TRM.

### Escalation Rate

In the 2021 TRC Test Tentative Order, the Commission proposed that any avoided electricity costs that require escalation from a given year would use the Bureau of Labor Statistics’ (BLS) Electric Power Generation Transmission Distribution (GTD) sector price index[[44]](#footnote-45) (BLS factor: NAICS 221110) as a proxy rate. The escalation statistic would be derived from the compound average growth rate (CAGR) of the average annual values of the prior four years with data for all twelve months.

The escalation rate deals with the rate of increase in costs in real dollars. The escalation rate is not to be confused with the rate of inflation. We proposed that the escalation rate plus the inflation rate captures the increase in cost projections in nominal dollars.

#### Comments

OCA agrees with the methodology proposed for the escalation rate and asks for clarification that the BLS GTD index cannot use preliminary data, and that the average annual values used be based upon the four years prior to the EE&C filing deadline. OCA Comments at 4-5.

OSBA requests that the Commission use a broader-based inflation index for which long-term forecasts are readily available, such as the GDP deflator or the Wholesale Price Index, rather than the GTD index. OSBA notes that the index proposed by the Commission is actually a generation sector only index, which is likely to be heavily influenced by fuel costs and that the proposed index shows negative real price changes over that past several years. OSBA also states that a historical four-year average does not represent a reasonable basis for a 15- or 20-year forecast, particularly for less stable indices such as the GTD index. OSBA Comments at 10.

PECO provides evidence from the BLS and the Federal Reserve Bank of Dallas indicating the GTD index is given in nominal dollars, rather than real dollars as stated in the 2021 TRC Test Tentative Order and avers that the Commission should continue to use the GTD index without an additional adder for inflation because the GTD index already captures the effects of inflation. PECO Comments at 6-7.

In reply comments, PECO states that it shares OSBA’s concerns and opposes the use of BLS NAICS 221110 index data to derive the escalation rate. PECO proposes two alternate approaches to calculate the escalation rate. In the first approach, the Commission would set the prescribed escalation rate at 2% (the inflation rate); in the second approach, the Commission would use BLS CPI-U index data (BLS CUUR0000SA0) instead of BLS NAICS 221110 index data. PECO Reply Comments at 2-4.

#### Disposition

We acknowledge comments from OSBA that the BLS GTD index may not be the most appropriate for all the components of avoided electricity cost forecasts and agrees with the evidence that PECO submits that the BLS GTD index is in nominal dollars. Consequently, we direct that all cost projections shall only be escalated by the 2% inflation rate and not include the application of any additional escalation index.

### Avoided Cost of Generation Capacity

Generation capacity for the region is procured through PJM’s forward capacity auction process – the Reliability Pricing Model. The BRAs occur approximately three years prior to the beginning of the delivery year, so the actual generation capacity value for the first years of the forecast horizon are known. When available, the actual zonal BRA clearing prices are to be used as the values for the avoided cost of generation capacity. When projecting further into the future than the known values, the Commission proposed, in the 2021 TRC Test Tentative Order, the following methodology:

1. Use a simple average of the three most recent BRA clearing prices for the zone. The Commission’s position was that taking a three-year average is prudent because clearing prices vary from year-to-year, and an average will dampen this volatility. For Phase IV EE&C plans, EDCs should have actual BRA clearing price values for the 2021/2022, 2022/2023, and 2023/2024 delivery years (PY13, PY14, and PY15).[[45]](#footnote-46)
2. Use this value as the avoided cost of capacity for the first year that BRA clearing pricing prices are not available.
3. Escalate using a compound annual growth rate of the BLS index for the power sector to calculate the avoided cost of generation capacity in real dollars for the remainder of the forecast horizon.
4. Apply the inflation rate of 2% to convert real dollars to nominal dollars.

#### Comments

 FirstEnergy comments that because the historic auction results are in nominal dollars, the 3-year historic average auction value should be escalated and inflated beginning in the first year to more appropriately reflect current conditions. FirstEnergy Comments at 3.

 The Industrials support the proposed change in methodology. Industrials Comments at 12-13.

 PECO requests clarification as to whether its reference to “actual zonal BRA clearing prices” refers to the “Resource Clearing Price,” the “Preliminary Zonal Capacity Price,” or the “Preliminary Zonal Net Load Price” and notes that the Commission uses the “Preliminary Zonal Capacity Price” under the current 2016 TRC Test. PECO Comments at 8.

#### Disposition

FirstEnergy is correct that BRA clearing prices are in nominal dollars and that inflation must be accounted for prior to averaging the three most recent auction results. Prior to performing the three-year average, EDCs are directed to inflate the clearing prices for the three most recent available delivery years using a 2% inflation rate to calculate the clearing price in nominal dollars for the first year without auction results. This change has been reflected in the formulae of the ACC. The disposition of the prior section (Escalation Rate) also impacts the calculation of the avoided cost of generation capacity. Step iii, above, is no longer necessary as the 2021 TRC Test will assume no escalation other than inflation.

Although no stakeholders commented directly on this issue, it is worth noting that the timeline for upcoming Base Residual Auctions at PJM is somewhat uncertain. The BRA for the 2022/2023, which normally would have happened in May 2019, has not occurred as of the writing of this Order. It seems likely that the BRA for the 2023/2024 delivery year will not occur in May 2020. Regardless of which BRAs have, and have not occurred, when an EDC develops avoided costs for Phase IV, the underlying direction is the same. (1) Use actual BRA clearing prices for years the auction has occurred, and (2) use an average of the three most recent auction clearing prices as the basis of the forecast for those years for which the BRA has not yet occurred.

In response to PECO’s request for clarification about the zonal clearing price to use, the Commission directs EDCs to use the “Adjusted Preliminary Zonal Capacity Price”. In the ‘Summary’ tab of the 2021/2022 Base Residual Auction results workbook,[[46]](#footnote-47) this corresponds to cells C25:C45.

### Avoided Cost of Transmission and Distribution Capacity

 In the 2021 TRC Test Tentative Order, the Commission proposed to continue the status quo Act 129 methodology with slight modifications for the calculation of avoided T&D capacity costs. Each EDC provided capital expenditure data, as requested by the Phase III SWE, that were used to produce input assumptions for the Phase IV market potential study which are reflected in Table 1 and Table 2, using the following calculations:

1. Use 15 years of data on summer and winter peak load and growth rates by zone from the January 2019 PJM Load Forecast Report.
2. Use five-year forecasted annual load-growth related capital expenditures for T&D investments, as provided by each EDC.
3. Calculate the EDC-specific yearly average for T&D expenses and estimated load growth. Load growth average was calculated by taking the difference in forecasted summer peak loads each year then averaging these values across all 15 years.
4. Divide the average annual load growth related expenditures by the average change in load growth to get the avoided cost in $ per kW.
5. Apply a fixed charge rate of 18% to convert the average T&D investment per kW of load growth to an annualized ($/kW-year) avoided cost.

The fundamental calculation was proposed to stay consistent, but the order of operations would be modified from the Phase III calculations.[[47]](#footnote-48) This system-wide perspective is a simplification of the underlying characteristics of EDC systems, which have areas of load growth and areas of load decline. It is also important to note that the zonal peak load forecasts exhibit limited growth (less than 0.5% annually), which leads to a small denominator. The proposed Phase IV values were generally higher than Phase III values, largely because of the limited amount of growth in the Pennsylvania zonal peak load forecasts.

We found that inconsistencies in EDC reporting of planned capital expenditures to the Phase III SWE have led to highly variable results across the state. We also recognize that DR cost-effectiveness will be sensitive to these assumptions as DR programs primarily produce capacity (kW) benefits as opposed to energy benefits (kWh).

Despite these limitations, the Commission’s experience is that this method is a cost-effective, pragmatic calculation strategy and common industry practice. A more rigorous study would impose timing and budget constraints on the Phase IV market potential studies and require significant coordination with EDC system planners. Therefore, we did not propose to conduct additional research on this topic in preparation for a potential Phase IV.

In the 2021 TRC Test Tentative Order, the Commission proposed that EDCs use avoided cost of T&D capacity rates, as shown in Table 1 and Table 2. All values are in real dollars ($2021). For the Phase IV market potential studies, the Phase III SWE escalated costs by 1.16% annually based on the BLS CAGR calculation at the time of analysis. We proposed that EDCs be required to apply an inflation rate of 2% per annum and an updated escalation rate to the 2021/2022 values in the tables when producing forecasts for their Phase IV EE&C plans. EDCs would use the ACC to calculate escalation rates.

Table 1: Avoided Cost of Transmission Capacity Forecast by EDC ($/kW-year)[[48]](#footnote-49)

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Year | PECO | PPL | DUQ | ME | PN | PP | WPP |
| PY13 (2021-2022) | $24.96 | $0.00 | $31.27 | $25.08 | $30.41 | $0.00 | $0.17 |

Table 2: Avoided Cost of Distribution Capacity Forecast by EDC ($/kW-year)[[49]](#footnote-50)

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Year | PECO | PPL | DUQ | ME | PN | PP | WPP |
| PY13 (2021-2022) | $105.81  | $121.21  | $16.29  | $70.05  | $46.08  | $19.05  | $23.38  |

 Customers in the Large C&I class generally take service at primary voltage and own their own transformers rather than rely on EDC transformers. The 2016 TRC Test Order specified that the avoided cost of distribution capacity was not to be applied to DR measures. The Commission has been informed by the Phase III SWE, that EDCs have been unclear whether EE measures that have peak demand reductions should also be excluded from using the avoided cost of distribution capacity. For clarification, the Commission proposed that no avoided cost of distribution capacity be assigned to EE peak demand reductions from participants in the Large C&I class.

 We recognize that EDC tariffs vary, so Large C&I customers will possibly map more cleanly to the rate codes of some EDCs than to the rate codes of other EDCs. We presumed that, as a general rule, application of the avoided cost of distribution capacity to residential customers and non-residential customers who take service at secondary voltage will be manageable for all the EDCs after the proposed exclusion of the Large C&I customers that take service at primary voltage.

#### Comments

OSBA avers that while it is difficult to estimate T&D costs related to load growth, the Commission’s proposed approach is likely to overstate cost estimates. OSBA notes specifically that the proposed avoided distribution charges for PECO and PPL are much higher than the $/kW demand charge for commercial customers in those territories, and recommends that, in light of the large difference, the Commission direct the SWE to study PPL and PECO avoided distribution costs at a more detailed geographic level. In addition, OSBA states that it was unable to locate the source for the avoided T&D values shown in Table 1 and Table 2 and requests that the studies and underlying data for the avoided T&D cost analysis be made available for public review. OSBA Comments at 10-11.

Duquesne and KEEA commented on the applicability of avoided distribution costs for Large C&I customers. Duquesne states that the proposed change is inappropriate because it will understate benefits for C&I customers who take service at the distribution level and will be punitive for EDCs such as Duquesne with significant numbers of such customers. Duquesne Comments at 3. KEEA avers that the proposed change is also not appropriate, because the TRC counts “total costs – including participant costs – [and so] it must count total benefits, including the avoided costs of distribution upgrades, even if the distribution equipment exists behind the utility meter.” KEEA Comments at 2.

PECO supports the use of the GTD index for escalation rates but states that addition of an inflation adder would not be appropriate, as described in section B.5. Escalation Rate of this Order. PECO Comments at 8.

#### Disposition

Duquesne misinterprets the proposed guidance in the 2021 TRC Test Tentative Order with respect to which customers should receive avoided cost of distribution capacity benefits. We clearly noted that the mapping of this benefit stream should be tied to service voltage. Peak demand savings from projects completed by customers who take service at secondary voltage from Duquesne should be assigned the avoided cost of distribution capacity. For Duquesne, the distinction described in this Order would presumably only apply to customers on the HVPS (High Voltage Power Service) tariff were service is provided at 69,000 volts or higher. As proposed in the 2021 TRC Test Tentative Order, EE&C projects completed by customers who are served at the distribution level should be assigned the avoided cost of distribution capacity.

KEEA is correct that benefits which accrue to the participant, such as reduced cost to expand, replace, or maintain transformers or other behind-the-meter distribution equipment, should be considered TRC benefits. However, the Commission views these as O&M benefits and not part of the marginal cost of the electric system. As discussed in Section C.6, O&M Benefits, these benefits are part of the Phase IV TRC Test for Act 129 programs and EDCs are encouraged to work with participating customers to capture and monetize such savings in the TRC Test where appropriate.

The Commission agrees with OSBA that the avoided cost of distribution capacity values produced by the Phase III SWE in preparation for the Phase IV market potential studies exhibits a surprising amount of variation across EDCs. We do not plan to release the underlying data and analysis as part of this proceeding. However, we will direct the Phase IV SWE, in collaboration with EDC system planners, to develop a more granular alternative methodology for the avoided cost of T&D capacity in Pennsylvania. The status quo calculation methodology is predicated on some amount of overall growth in the peak demand forecast. We understand that a methodological change will be inevitable as some EDCs begin to experience flat or declining peak demand forecasts but still experience growth-related capital expenditures in certain areas of their systems.

For Phase IV of Act 129, EDCs are directed to use the avoided T&D values presented in Table 1 and Table 2, escalated for inflation at 2% annually to monetize peak demand reductions from EE&C plan projects completed by participants who take service at secondary voltage. For program participants who take service at primary voltage, only the avoided cost of transmission capacity (Table 1) is applied.

### Compliance with Alternative Energy Portfolio Standards Act (AEPS)

In Phase I and Phase II, the Commission required that the costs of compliance with the AEPS Act[[50]](#footnote-51) that are known and knowable be included in the TRC Test calculation. The cost was applicable to all the power “avoided.” Further, for Phase II, it was noted that a reduction in electric consumption would reduce an EDC’s costs of complying with the AEPS Act requirements. *See 2013 TRC Test Order* at 44-45.

To date, no EDCs have included avoided AEPS Act costs, as quantified in avoided alternative energy credit (AEC) purchases, in their TRC Test calculations. Pricing for AECs has varied widely: the average low price for a Tier 1 AEC from 2008 to 2018 was $0.74 while the average high price was $72.66.[[51]](#footnote-52) Also, the AEPS Act, as modified by Act 40 of 2017, established geographical limits on solar photovoltaic (solar PV) systems that qualify for the solar PV share requirement of the AEPS Act, which has affected the price stability of solar AECs.[[52]](#footnote-53) To ensure uniform valuation of AECs (and hence avoided cost estimates) by EDCs in their EE&C plans, the Commission’s proposal in the 2021 TRC Test Tentative Order was to provide EDCs with AEC pricing for use in Phase IV planning.

 The Commission has access to several subscription-based services that forecast AEC pricing, including Marex Spectron.[[53]](#footnote-54) Using forecast data for the year 2021, the Commission proposed that the AEPS Act avoided costs would be $0.84 per MWh for the first year of Phase IV and escalated by the BLS escalation factor every year thereafter.[[54]](#footnote-55) We proposed this change because the 2016 TRC Order directed EDCs to include this benefit stream, but none of them did. This rendered the value to be effectively zero during Phase III.

#### Comments

The Industrials propose that the Commission or the SWE include actual avoided cost values in the annual reports by each EDC, based on actual market costs, and that if actual AEPS costs diverge from the forecasted values, parties should be permitted to seek changes to the forecasts to better reflect actual AEPS market conditions. Industrials Comments at 13-14.

OSBA supports the proposed method for calculating avoided AEPS compliance costs but suggests that AEPS compliance costs might not be best escalated using the BLS generation index, as indicated by OSBA’s comments regarding the GTD index in section B.5. OSBA Comments at 12.

PECO notes that in the 2021 TRC Test Tentative Order, the Commission proposed that the AEPS Act avoided costs will be $0.84 per MWh for the first year of Phase IV, but in the ACC model the “AEPS” Tab calculates this value to be $0.83 per MWh. PECO requests clarification as to whether $0.84/MWh or $0.83/MWh will be used and whether the value will be updated based on the most current data available. PECO Comments at 9.

#### Disposition

The Commission will not adopt the Industrials’ suggestion to have the SWE provide AEPS costs to EDCs annual for inclusion in EDC annual reports. However, we will direct the Phase IV SWE to include a summary of the AEPS costs with its Phase IV annual reports for comparison purposes. If this comparison reveals significant differences between the assumed forecasted AEPS and the actual future AEPS costs, the Commission reserves the right to require a mid-phase update to avoided cost forecasts should the variance become large enough to fundamentally alter the benefit/cost results at the portfolio level.

Based on other stakeholder comments and for consistency within the 2021 TRC Test Final Order, the Commission directs future AEPS costs to be escalated using the 2% inflation rate over the forecast horizon. Use the escalation rate only and do not include the application of the BLS index to escalate forecasted costs.

In response to PECO’s request for clarification on the amount of the AEPS avoided costs, the Commission clarifies that the AEPS avoided cost shall be $0.834 per MWh for consistency with this 2021 TRC Test Final Order and the ACC. These values will not be updated unless the Commission provides direction to do so based on a meaningful change in the AEPS avoided costs found by the Phase IV SWE research.

### Price Suppression Effects

In organized markets, such as the capacity, energy, and ancillary services markets operated by PJM, reductions in demand tend to place downward pressure on the supply side of the market and can potentially lower the market equilibrium price, also known as Demand Reduction Induced Price Effects (DRIPE).[[55]](#footnote-56) The Commission expressed concerns about inherent uncertainty associated with quantifying this presumed benefit stream of DRIPE as a TRC benefit.

This issue has been investigated previously by the SWEs and discussed in prior Commission Orders. In a Secretarial Letter, dated May 17, 2013, the Commission released the *Act 129 Demand Response Study – Final Report* at Docket No. M­2012­2289411.[[56]](#footnote-57) The Commission held a DR Study Stakeholders’ Meeting on Tuesday, June 11, 2013. At the suggestion of stakeholders, the Commission directed the Phase II SWE to conduct a Preliminary Wholesale Price Suppression and Prospective TRC Test Analysis of the DR program. The Phase II SWE’s *Act 129 Demand Response Study – Final Report; Amended November 1, 2013*[[57]](#footnote-58) was released for comment on November 14, 2013.[[58]](#footnote-59) Following a review of comments, the Commission issued its Peak Demand Reduction Cost Effectiveness Determination Final Order, which directed the Phase II SWE to perform a DR Potential Study.[[59]](#footnote-60) In the Peak Demand Reduction Cost Effectiveness Determination Final Order, the Commission was persuaded by stakeholder comments recommending against further price suppression research and directed the Phase II SWE to perform a DR Potential Study for Phase III without inclusion of price suppression benefits. Based on the information amassed, no price suppression benefits were included in the 2016 TRC Test Order for energy efficiency or DR.

In the 2021 TRC Test Tentative Order, the Commission proposed to maintain the current Act 129 position on price suppression effects. While we agree that such effects may exist, we have significant concerns about the level of effort required to quantify and monetize the effects over a twenty-year forecast horizon. Based upon the extent of research conducted in other jurisdictions, the Commission’s position is that such research would not be a prudent use of ratepayer funds as the findings of such an analysis – no matter how rigorous – would be speculative at best and require numerous assumptions about future market structures and the complex interactions between supply and demand resources[[60]](#footnote-61) in competitive markets.

#### Comments

AEMA, KEEA, and PA-EEFA all suggest that the Commission should re-consider whether a reasonably accurate calculation of price suppression effects is possible. AEMA states that the Commission’s proposed position does not acknowledge recent analyses and modeling from other states, and that other states include DRIPE impacts in their benefit-cost analyses. AEMA Comments at 8. KEEA notes that the Phase II report and stakeholder process to examine the accuracy of price suppression effects was in the context of a demand response potential study, not energy efficiency, and that past preliminary analysis found that price suppression effects could increase TRC benefits by roughly 50 percent in some cases. KEEA Comments at 2-3. PA-EEFA states that a study that could achieve a reasonable plausible estimate could be done at lower cost than the Commission assumes. PA-EEFA Comments at 6.

The Industrials support the Commission's position that price suppression effects are highly speculative and should not be included in the TRC Test. Industrials Comments at 14.

OSBA takes no position on whether to include price suppression effects but states that there should be consistency between EDC and NGDC EE&C plans in how the issue is treated. OSBA Comments at 12.

In reply comments, EAP agrees with the Commission’s proposed position on price suppression effects and asks the Commission to reject commentators’ suggestions to reconsider the impact of price suppression effects in the 2021 TRC Test. EAP Reply Comments at 4-6.

In reply comments, the Industrials re-affirm their initial comments that price suppression effects should be excluded from the TRC Test. Industrials Reply Comments at 9.

#### Disposition

The Commission is not persuaded by the comments from AEMA, KEEA, and PA‑EEFA suggesting that DRIPE be considered in the development of avoided costs for Act 129 programs. KEEA is correct that we have not directed the SWE to examine this issue in detail since 2013. However, none of the parties suggesting that DRIPE be included set forth a recommended methodology or provide reference to studies from states or program administrators within the PJM footprint. The avoided costs for Phase IV of Act 129 will not include any DRIPE, but we will direct the Phase IV SWE to monitor this issue and provide recommendations regarding the methodology, cost, and timeline of a study to re-examine capacity and/or energy DRIPE in the Commonwealth.

### End-Use Adjustments

In the 2021 TRC Test Tentative Order, the Commission proposed to continue the use of end-use profiles, when available, for EE&C technologies or programs with profiles using a time differentiated format consistent with the avoided energy costs. When device-specific profiles are not available, the use of class average premise loads would continue to be acceptable.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

As proposed, the Commission directs EDCs to use end-use profiles when available for EE&C technologies or programs with profiles using a time differentiated format. When device-specific profiles are not available, the use of class average premise loads will continue to be acceptable.

## Other TRC Benefits

Historically, there has been asymmetric handling of water and fossil fuel impacts in the Pennsylvania TRC Test, with increased fuel consumption from fuel switching measures treated as a cost in the TRC Test while conserved fuel and water were not accounted for as benefits in the TRC Test.[[61]](#footnote-62) The 2016 TRC Test Order and the Phase III Implementation Order required the inclusion of “reasonably quantifiable” water and fossil fuel benefits in the TRC Test. During PY9, the Phase III SWE issued a guidance memo dated March 25, 2018, to the EDCs and their evaluation contractors with instructions on how to treat fossil fuel and water impacts for the remainder of Phase III.

In the 2021 TRC Test Tentative Order, the Commission proposed to maintain the Phase III provisions as modified by the 2018 guidance memo, but proposed a series of guidelines and clarifications as to what constitutes “reasonably quantifiable” fossil fuel or water impacts. To promote consistent accounting practices across EDCs, the Commission proposed the following additional assumptions and calculated values for various measures incorporating water and fossil fuel savings.

### Quantifying Water Impacts

Water savings measures are two-fold in the sense that savings can occur through reductions in the quantity of water consumed and reductions in the heating energy that would have been used to heat this water. For some measures, the 2021 TRM provides estimates for water volume saved as an intermediate step to calculate energy savings. Sections 2.3.7 to 2.3.9 of the 2021 TRM (low flow faucet aerators, low flow showerheads, and thermostatic shower restriction valves, respectively), Section 3.4.2 of the 2021 TRM (low-flow pre-rinse sprayers) and Section 2.4.8 of the 2021 TRM (ENERGYSTAR dishwashers) give default values for gallons per minute and usage pattern variables, such as minutes per day, number of people per household, and number of showers per day per person. In the 2021 TRC Test Tentative Order, we proposed that these values be used to estimate gallons of water conserved per year.

Because residential faucets are used for both cold and hot water, additional information is needed. We proposed a value of 1,039 gallons/year as a reasonable annual savings assumption for low-flow faucet aerators, based on an average 8.1 minutes/day of faucet use. We proposed, therefore, to use a value of 1,039 gallons/year for 2021 TRC Test calculations. This value is taken from *1999 Residential End Uses of Water* (REU1999).[[62]](#footnote-63) Although the value from the REU1999 is dated, the more recent *2016 Residential End Uses of Water* (REU2016) states that the “average faucet use per household and per capita did not change at a statistically significant level from” REU1999 to REU2016.[[63]](#footnote-64)

ENERGY STAR clothes washers save water and energy, but the 2021 TRM does not provide enough information to calculate the water savings values. Based on the 2018 guidance memo that reflected the changes in clothes washer standards, it was proposed in the 2021 TRC Test Tentative Order to continue those savings assumptions based on fuel mix and washer type, as shown in Table 3 below.

Table 3: Water and Fuel Savings – Residential ENERGY STAR Clothes Washers[[64]](#footnote-65)

|  |  |  |  |
| --- | --- | --- | --- |
| Fuel Mix | Washer Type | Gallons/Year | Therms/Year |
| Electric Domestic Hot Water (DHW) & Electric Dryer | Top-Loading | 1,768 | 0.0 |
| Front-Loading | 1,222 | 0.0 |
| Electric DHW & Gas Dryer | Top-Loading | 1,768 | 0.2 |
| Front-Loading | 1,222 | 1.1 |
| Gas DHW & Electric Dryer | Top-Loading | 1,768 | 5.1 |
| Front-Loading | 1,222 | 4.8 |
| Gas DHW & Gas Dryer | Top-Loading | 1,768 | 5.3 |
| Front-Loading | 1,222 | 5.9 |
| Default (Unknown) Fuel Mix | Top-Loading | 1,768 | 2.2 |
| Front-Loading | 1,222 | 2.3 |

#### Comments

OSBA states that in general it supports the Commission’s efforts to calculate and monetize water savings associated with EE&C programs, and that to the extent practicable, such calculations should be standardized. OSBA cautions that valuing other TRC benefits such as reduced water consumption or increased fuel costs may unreasonably complicate evaluations. OSBA Comments at 12-13.

#### Disposition

The Commission agrees with OSBA that practicality and standardization are key for Phase IV of Act 129. As proposed, and consistent with the modifications in the 2018 guidance memo, we will only require EDCs to include TRC benefits from water savings for those measures where either the 2021 TRM provides all necessary inputs and assumptions to calculate them or this Order presents default savings levels.

### Monetizing Water Impacts

In the 2021 TRC Test Tentative Order, the Commission proposed that resources be monetized using a marginal cost to reflect what is reduced (or increased) by an EE&C measure, consistent with the 2018 guidance memo. Marginal costs are the appropriate perspective for the TRC Test because other fixed costs embedded in retail rates will still be recovered. We proposed that EDCs use $0.01 per gallon ($2021) as the marginal cost of water used for TRC testing. Under the proposal, this rate would be escalated yearly with the same inflation rate assumed throughout the TRC model. The marginal cost of water includes the energy required to pump and treat the water. In order to avoid double-counting, the Commission proposed that saved pumping energy from water measures would not be counted toward EDC compliance targets.

The 2021 TRM does not, however, include loss rates for water. Water systems experience losses in their distribution networks. The Commission proposed a loss factor of 24.5% (or 1.32 multiplier) for water losses based on a weighted average reported loss rate of 28 Class A water companies in Pennsylvania.

#### Comments

Duquesne agrees with the proposed methodology for standard energy efficiency projects that also result in water savings, such as replacement of a dishwasher with a more efficient model, but submits that infrastructure projects implemented by public water and wastewater utilities that result in measurable water savings, for example by fixing water mains and distribution feeders, can result in significant energy savings through the reduced treatment and pumping of water and should therefore be eligible for energy efficiency funding and should count towards an EDC’s Act 129 energy savings targets. Duquesne Comments at 3-4.

OCA disagrees with the Commission’s assumptions included in its marginal cost calculation and the water loss rate. OCA states that the assumptions are not documented or fully explained, and (a) the proposal includes an incorrect assumption that all electric customers are served by Class A water companies regulated by the Public Utility Commission; (b) there is no support for the use of a marginal cost of water of $0.01 per gallon or the need for an escalation rate; (c) there has been no demonstrated need to incorporate a water loss rate in the TRC, and the proposed 24.5% loss rate is above the 20% level considered by the Commission to be excessive; and (d) OCA is also not aware of any other utility in the country that incorporates a water loss rate. OCA Comments at 5-6.

#### Disposition

The Commission agrees with Duquesne that infrastructure projects implemented by public water and wastewater utilities can save significant amounts of electric energy. For Phase IV of Act 129, water utilities and municipal water authorities are eligible to participate in Act 129 programs, and EDCs are encouraged to claim the reduced pumping and wastewater treatment energy towards compliance targets. To clarify, our prohibition of counting the embedded energy in delivered water only applies to water-savings measures installed at an end-use home or business (*e.g.*, a low-flow showerhead or faucet aerator).

OCA is correct that not all EDC ratepayers are served by Class A water companies. Our use of Class A water companies to derive water assumptions is based on data availability and reporting requirements. We find that the loss rate experienced by Class A water companies is a reasonable proxy for the Commonwealth as a whole. While a lower water loss rate would certainly be preferable, the data show that water losses are 24.5%. The $0.01 per gallon avoided cost is not a retail rate, so the losses are not embedded. OCA, however, presents no evidence that the marginal cost of water does not increase with inflation. Given the fact that electricity is a significant portion of the operating cost of the water system, and we apply escalation to electricity in the avoided cost forecast, it follows that the avoided cost of water should also be escalated annually.

Therefore, for Phase IV of Act 129, we direct the EDCs to use $0.01 per gallon (in 2021 dollars) as the marginal cost of water used for TRC testing escalated annually over the forecast horizon, with a loss factor of 24.5% (1.32 multiplier) to be applied to all savings calculated at the end use level.

### Quantifying Fossil Fuel Impacts

In the 2021 TRC Test Tentative Order, the Commission proposed that EDCs should continue to include fossil fuel benefits, consistent with the 2016 TRC Test and the 2018 guidance memo.

We noted, however, that because of the number of different measures, program delivery models, and data collection practices, deciding how to include fossil fuel benefits has resulted in differences in methodology among the EDCs. While the EDCs and their evaluation contractors will need to continue to exercise some discretion in how to include fossil fuel impacts, the Commission proposed specific guidance for instances of residential new construction, air sealing and/or insulation, ENERGY STAR windows, and residential thermostats.

* Residential New Construction (2021 TRM Section 2.7.1) – If the building simulation model used to calculate kWh savings for residential new construction also provides annual gas savings, these impacts would be considered reasonably quantifiable and expected to be incorporated into the TRC analyses.
* Air Sealing and Insulation (2021 TRM Sections 2.6.1-2.6.4) – Savings assumptions for electrically heated homes that receive air sealing or insulation upgrades will be presumed to be reasonably transferrable to fossil fuel impacts. EDCs would be required to justify why the presumption is not applicable in any given case. The 2021 TRM algorithms calculate BTU impacts and then convert them to electric resource savings using the Heating Seasonal Performance Factor (HSPF). The default Annual Fuel Utilization Efficiency (AFUE) assumption used to convert BTU impacts to fuel savings would be 80%.
* ENERGY STAR Windows (2021 TRM Section 2.6.5) – The ENERGY STAR Windows measure algorithm is not very extensible to fossil fuel savings because it only provides a default kWh/ft2 assumption; therefore, this would not be “reasonably quantifiable.”
* ENERGY STAR Certified Connected Thermostats (2021 TRM Section 2.2.11) – The ENERGY STAR Certified Connected Thermostats measure includes almost all the information necessary to calculate fossil fuel savings because it quantifies the electric fan savings associated with gas furnaces. An assumed average capacity and AFUE value would be applied to complete the calculation for fossil fuel savings. The Phase III SWE has recommended using 60,000 BTU/hour and an AFUE of 80% as reasonable default values for Phase IV.

Faucet aerators, along with showerheads and thermostatic shower restriction valves, also reduce fossil fuel use when they are implemented in homes with non-electric heating. The 2021 TRM Table 2-76 presents the assumption that 35% of homes have electric water heat, indicating the remaining 65% have natural gas, propane, or fuel oil. Based on the Phase III SWE recommendations, we proposed a simplified assumption that all non-electric resource savings be monetized using natural gas avoided costs for Phase IV. This conservative assumption should reduce additional work required to calculate and monetize fossil fuel impacts as TRC benefits. The Commission proposed the use of 80% recovery efficiency for gas units to monetize any non-electric resource savings.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

As no stakeholders commented on this topic, we direct the EDCs to calculate fossil fuel impacts as described above.

### Interactive Effects

Installation of LED lighting reduces the amount of waste heat produced by the lighting end-use. TRM protocols quantify the electric impacts on the HVAC system, so the electric interactive effects are reflected in the calculation of TRC benefits. In the case of homes or businesses with fossil fuel heating systems, the increased heating fuel consumption should continue to be treated as a negative benefit in the TRC. *See* Section E.2 Increased Fuel Consumption, below, regarding the proposed change in the calculation for increased fuel consumption.

The 2021 TRC Test Tentative Order, however, proposed a standardization of reporting the heating penalties as a negative benefit in the 2021 TRC Test for efficient lighting. We also proposed that all EDCs consistently calculate and report the heating penalties. Inputs shown in Table 4 below for fuel share come from Table 201 in the 2018 Residential Baseline Study,[[65]](#footnote-66) and inputs for percentage of lamps installed in interior sockets should be drawn from the Total Average per Home values provided in Table 5-50 and Figure 5‑12 in the 2014 Residential Baseline Study.[[66]](#footnote-67)

Table 4: Residential Lighting Gas Heating Penalties by EDC

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| EDC | Gas Heat Fuel Share | % Lamps Interior | Lighting Savings in Heating Season | Waste Heat Escape | Furnace AFUE | Heating Penalty (Therms per kWh) |
| PECO | 61% | 92.00% | 65.5% | 20% | 0.8 | 0.01254 |
| PPL | 25% | 90.48% | 65.5% | 20% | 0.8 | 0.00506 |
| Duquesne Light | 78% | 92.00% | 65.5% | 20% | 0.8 | 0.01604 |
| FE: Met-Ed | 56% | 88.52% | 65.5% | 20% | 0.8 | 0.01108 |
| FE: Penelec | 61% | 91.30% | 65.5% | 20% | 0.8 | 0.01245 |
| FE: Penn Power | 72% | 92.42% | 65.5% | 20% | 0.8 | 0.01487 |
| FE: West Penn | 49% | 90.48% | 65.5% | 20% | 0.8 | 0.00991 |

The formula for heating penalty (therms per kWh of lighting savings) is:

$$Penalty =fuel share\*\% interior\*\% heating season\*\left(1-escape\right)\*\frac{0.03412}{AFUE}$$

The Commission proposed a choice between two methods for impact estimates of non-residential lighting. The EDCs would be able to choose between these options depending on the factors of a given job. In reporting results, the EDCs would need to clearly indicate which option was chosen and show their work. The two options are:

1. Calculate a therms/kWh penalty for buildings with gas heat and apply it to savings from indoor lighting projects with non-electric heating systems. This calculation would mimic Table 4, with the first two columns equal to 100%.
2. Use the 2018 Non-Residential Baseline Study[[67]](#footnote-68) or program records to calculate overall assumptions about the heating penalty. This approach would assume a gas heating fuel share and percent of lamps installed in conditioned spaces and produce a therms/kWh factor to apply to all non-residential lighting savings. The 2018 Non-Residential Baseline Study estimates 85% of statewide space heating capacity is supplied by natural gas and 94% of statewide non-residential lighting is installed indoors.

#### Comments

OSBA notes that the 2021 TRC Test Tentative Order only refers to a heating penalty in homes with fossil fuel heating systems. OSBA further states that the heating penalty should be applied to oil-heated homes as well, and not only natural gas-heated homes as proposed. OSBA Comments at 13.

#### Disposition

Interactive effects from efficient lighting installations in businesses with electric heat have been captured in the Pennsylvania Technical Reference Manual since the 2009 TRM and interactive effects from homes with electric heat were added in the 2014 TRM. The objective of the TRM is to capture the electric impacts of EE&C measures. The impact of EE&C measures on fossil fuel consumption is a TRC matter, therefore we proposed to address interactive effects in homes with fossil fuel heat in the 2021 TRC Test Tentative Order.

The Commission agrees with OSBA that heating penalties are to be applied to homes and businesses with fuel oil and propane heat as well as natural gas heating systems. Table 5 provides an updated table of default residential values that includes the addition of the share of homes heated by these fossil fuel resources as well as changes in the heating penalty[[68]](#footnote-69). As discussed in the following section, Phase IV Act 129 programs will utilize a simplifying approach of monetizing all fossil fuel impacts using the avoided cost of natural gas rather than requiring a separate avoided cost forecast for fuel oil and propane and tracking heating fuel distributions among EE&C plan participants with fossil fuel heat.

Table 5: Residential Lighting Heating Penalties by EDC

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| EDC | Fossil Fuel Heat Fuel Share | % Lamps interior | Lighting Savings in Heating Season | Waste Heat Escape | Furnace AFUE | Heating Penalty (Therm per kWh) |
| PECO | 81% | 92.00% | 65.50% | 20% | 0.8 | 0.0167 |
| PPL | 61% | 90.48% | 65.50% | 20% | 0.8 | 0.0123 |
| Duquesne Light | 82% | 92.00% | 65.50% | 20% | 0.8 | 0.0169 |
| FE: Met-Ed | 74% | 88.52% | 65.50% | 20% | 0.8 | 0.0146 |
| FE: Penelec | 82% | 91.30% | 65.50% | 20% | 0.8 | 0.0167 |
| FE: Penn Power | 78% | 92.42% | 65.50% | 20% | 0.8 | 0.0161 |
| FE: West Penn | 67% | 90.48% | 65.50% | 20% | 0.8 | 0.0135 |

### Monetizing Fossil Fuel Impacts

In the 2021 TRC Test Tentative Order, the Commission proposed that all resources be monetized using a marginal cost to reflect what is reduced (or increased) by an EE&C measure. Other fixed costs embedded in retail rates would still be recovered. The marginal cost of natural gas is used as an input to the avoided cost of electricity forecast, as described in Section B.2 Avoided Cost of Electric Energy, of this Final TRC Test Order. We proposed that EDCs use the natural gas values in this forecast, collapsed to a single annual value, to monetize fossil fuel savings and increased consumption of fossil fuel that result from installation of EE&C measures.

By way of clarification, the methodology entailed the use of a 20-year period for calculating avoided electricity energy costs and was dissected into three segments.

**The first segment – years one through four**: The methodology for segment one would use short-term market-based NYMEX natural gas futures prices.

1. Use NYMEX natural gas futures prices at Henry Hub for years one through four. The prompt month for NYMEX futures is established as three months prior to the filing date.
2. Use the differential between the Henry Hub as the source and TETCO M-3 as the destination for the locational basis adjustment to the natural gas prices for utilities west of the Susquehanna River. The locational basis adjustment to the natural gas prices for utilities east of the Susquehanna River was the basis differential between the Henry Hub as the source and Transco Zone 6 non-New York as the destination.
3. Average monthly NYMEX natural gas prices into a single annual value.

**The second segment – years five through ten**:The methodology for segment two should be based on NYMEX natural gas futures. Medium-term NYMEX natural gas futures would be blended with the longer-term AEO projected natural gas costs across the segment 2 period to shift from market-based conditions to a more stable model that is public and transparent.

1. Gather NYMEX natural gas futures at Henry Hub for years five through ten. The prompt month for NYMEX futures is established as three months prior to the filing date. Monthly NYMEX natural gas prices would be averaged to a single annual value.
2. Use the differential between the Henry Hub as the source and TETCO M-3 as the destination for the locational basis adjustment to the natural gas prices for utilities west of the Susquehanna River. The locational basis adjustment to the natural gas prices for utilities east of the Susquehanna River was the basis differential between the Henry Hub as the source and Transco Zone 6 non-New York as the destination. For EDCs that have service territory on both sides of the river, such as PPL Utilities and Metropolitan Edison, the location would be based where the majority of the electric load is present.
3. Gather annual forecasted natural gas costs from the 2020 AEO projected costs for Electric Power Users in the Mid-Atlantic region using real dollars.
4. Derive final natural gas costs by blending together NYMEX natural gas futures and the AEO projected natural costs over the segment two period. The Commission proposed that this would be calculated by adding one-seventh of the differential between AEO natural gas costs and locational adjusted NYMEX natural gas futures for each segment year starting in year five to the zone location adjusted NYMEX natural gas futures.

**The third segment – years eleven through twenty**: The methodology for segment 3 would now use long-term market-based AEO projected natural gas costs for increases and decreases.

The 2021 TRM does not include loss rates for natural gas; however, natural gas companies also experience losses in their distribution networks. In the 2021 TRC Test Tentative Order, the Commission proposed EDCs use a natural gas loss factor of 4.167% (1.04167) based on the Phase III SWE’s calculations from data provided by the Pipeline and Hazardous Materials Safety Administration.

#### Comments

For comments regarding the natural gas price forecast, see the comments in Section B.2, Avoided Cost of Electric Energy, above. For comments regarding consistency between the Act 129 avoided cost of natural gas forecast and the values used by NGDCs in their EE&C plans see the comments in Section A.1, TRC Test Assumptions in Other Matters, above.

#### Disposition

The Commission’s decision regarding the natural gas price forecast is discussed in the disposition of Section B.2, Avoided Cost of Electric Energy. The Commission’s decision regarding consistency between the Act 129 avoided cost of natural gas forecast and the values used by NGDCs in their EE&C plans is discussed in the disposition of Section A.1, TRC Test Assumptions in Other Matters.

### O&M Benefits

The Commission’s position on O&M benefits has been largely unchanged since Phase I. O&M benefits, including avoided replacement costs and labor, should be included as TRC benefits. In cases where such costs were challenging to quantify, or unquantifiable, the Commission permitted EDCs to omit such costs from TRC calculations. A common example of avoided replacement costs and labor occurs with LED lighting systems in C&I facilities.

Because LED lighting equipment has a significantly longer rated lifetime than inefficient lighting equipment, the program participant will avoid both the equipment and labor cost of replacing the inefficient lighting when it would have failed, while the incented LED lighting equipment is still operational. Such benefits should not be challenging to quantify, and the SWE has provided default assumptions about O&M benefits from LED lighting measures in its Incremental Cost Database. EDCs should continue to quantify such benefits.

O&M benefits can be positive or negative. CHP systems, for example, will often have negative O&M benefits. If a project has ongoing maintenance costs relative to the baseline equipment, those costs should continue to be included as negative O&M benefits.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

As proposed, we direct the EDCs to continue to include O&M benefits in the TRC Test as either positive or negative TRC benefits.

### Societal Benefits

In the 2021 TRC Test Tentative Order, the Commission proposed, consistent with prior TRC Test Orders, that the TRC Test would not include societal benefits such as carbon dioxide emissions reductions or other environmental benefits, decreased universal service program costs, reduced uncollectible expenses, or any other non-energy impacts (NEIs) beyond the quantifiable fossil fuel, water, and O&M impacts detailed elsewhere in this section. *See 2016 TRC Test Order* at 8-16.

#### Comments’

Several parties commented on the proposal to not include societal benefits in the Phase IV TRC Test.

AEMA avers that, given Pennsylvania Governor Wolf’s announced plans to join the Regional Greenhouse Gas Initiative (RGGI), the Commission should value avoided carbon emissions in the TRC Test. AEMA Comments at 8. KEEA requests that the Commission include participant health benefit values because such benefits are not “hard to quantify” and are commonly included in the TRC Tests of other states’ with similar mandates. KEEA Comments at 3-4. The Joint Intervenors state that the Commission should justify why it proposes to not include non-electric benefits besides appealing to past decisions, and that in particular health benefits should be included because they can no longer be said to be “hard to quantify.” Joint Intervenors Comments at 5-6.

The Joint Intervenors additionally state that the Commission should align the 2021 TRC Test with the Commonwealth’s policy goals and that there are several Commonwealth policies and statutes that strongly suggest the Commission should consider the economic development impacts of its energy efficiency policies. Joint Intervenors Comments at 7‑10. The Joint Intervenors suggest that exclusion of “non-energy” benefits in the 2021 TRC Test leads to a lack of symmetry between TRC costs and benefits. Joint Intervenors Comments at 11.

OSBA takes no position as to whether carbon costs or other environmental externalities should properly be included in the benefits for an EDC EE&C plan but notes that including an expected carbon tax in the avoided costs would presumably require the Commission to rely on a different price forecast for natural gas in order to reflect the effect of reduced demand due to carbon taxes. OSBA Comments at 13-14.

Finally, regarding decreased universal service program costs and reduced uncollectible expense, PA-EEFA states that the Commission should include reduced universal service and uncollectible expenses in the calculation because these benefits are both quantifiable and clearly associated with the monetary cost of suppling service. PA‑EEFA Comments at 6-9.

In reply comments, EAP states that it agrees with the Commission’s proposed position on societal benefits and asks the Commission to reject commentators’ suggestions to reconsider the impact of societal benefits in the 2021 TRC Test. EAP Reply Comments at 4-6.

In reply comments, the Industrials object to the Joint Intervenors’ proposal to include non-energy benefits in the TRC Test and state that the Environmental Rights Amendment is not applicable to this energy cost-focused social program. Industrials Reply Comments at 7-8.

In reply comments, OCA submits that health benefits are not easily quantifiable and vary substantially among states that do include such benefits in their cost-effectiveness tests, and that health benefits should not be included as part of the TRC Test. OCA Reply Comments at 5-6.

#### Disposition

While Governor Wolf’s Executive Order EO 2019-07[[69]](#footnote-70) regarding Pennsylvania joining RGGI signals an increased consideration of emissions in Commonwealth policy, no law has been enacted at the time of this Order. To properly account for RGGI participation and the associated effects on avoided costs, the SWE would need to know the magnitude and value of the allowances and other key details. Until such time as the Legislature acts upon the Governor’s Executive Order, we conclude that it is premature to value emissions in the 2021 TRC Test. Furthermore, the costs to the owners of electric generating plants required to purchase emissions offsets would be passed along to ratepayers as part of the cost of electric generation and therefore would, at such time, become a relevant component of the TRC calculation.

The Commission recognizes the concerns of parties who highlight the exclusion of potential health and safety and economic development benefits of EE&C plans in the TRC Test. In reviewing information provided in comments and our own research, the most common approach other jurisdictions use to monetize these benefits is through “adders” that increase TRC benefits by some amount. We are not persuaded to allow inclusion of adders in the TRC benefits, especially given the large variance in the size of benefits among states that do quantify health benefits that OCA identifies in its reply comments.

Therefore, we determined that PA-EEFA’s comments regarding reduced arrearages and uncollected debt merit further investigation, particularly for programs offered to the low-income sector, and will direct the Phase IV SWE to study the impacts of EDC low-income programs on collections. We will make, at a later time, recommendations regarding the appropriateness and magnitude of such a benefit for consideration in future TRC Test Orders.

## TRC Costs

### Program Administration and Overhead

In the 2021 TRC Test Tentative Order, the Commission proposed that all program administration and overhead costs are to be treated as a TRC cost regardless of whether the labor, materials, and other fees are incurred by EDC staff, a CSP, or evaluation contractor. Common categories of administration cost are program design, program management, technical assistance, marketing, program delivery, and evaluation. SWE audit costs should also be considered a program administration and overhead cost. CSP contracts and EDC cost tracking should be structured in a way to provide maximum stakeholder visibility into non-incentive cost elements.

Some administrative costs, like a program tracking system or legal counsel, are challenging to allocate to specific programs. EDCs would continue to have the flexibility to incorporate these cross-cutting costs at the portfolio level or allocate them across programs using energy savings, budget, or some other logical allocation method. The treatment of cross-cutting costs, as well as a breakdown of cross-cutting cost components, would continue to be included in the EDC EE&C plans and final annual reports.

The Commission’s perspective on the categorization of equipment costs for direct install programs has, however, changed relative to previous phases. The 2013 TRC Test Order stated that we “see no reason to characterize the cost of direct installation programs that did not involve a payment to the participant as an incentive. Such costs are direct costs, not incentives.” *See 2013 TRC Test Order* at 17. This position was echoed in the 2016 TRC Test Order. The cost of kit measures has not been addressed in prior TRC Test Orders, but, during Phase III, we directed that phase’s SWE to clarify that the equipment cost of kit measures be considered incentives in the EDC annual report template. The treatment of kit and directly installed equipment does not affect the B/C calculation because the incremental cost is unaffected. However, the categorization of costs is an area of interest for stakeholders. Some parties have scrutinized the ratio of incentive costs to direct costs and characterized the direct costs of EE&C programs as wasteful relative to incentive spending. This appears to create an unfair perception issue for direct install and kit programs simply because of the program delivery mechanism.

For Phase IV, we proposed that kit and directly installed equipment costs be treated as IMCs and incentives. For example, if an EDC provides a low-flow showerhead to a program participant in a kit that costs $5 wholesale for the EDC, a TRC cost of $5 would be used. The IMC is $5, the incentive to participants is $5, and the participant cost net of incentives is $0. The shipping cost of the kits would still be treated as a non-incentive program delivery cost. The labor cost to directly install equipment would be included in the IMC and categorized as a participant incentive.

#### Comments

The Industrials aver that program administration and overhead must be accurately reported and evaluated, and that they are concerned that a significant portion of the costs paid by customers into the programs are being used for EDC or CSP administration and are not being returned to customers. Industrials Comments at 15.

OSBA and PA-EEFA both support the Commission’s proposed determination that kits and direct install program costs should be characterized as incentive costs rather than direct costs. OSBA Comments at 14. PA-EEFA Comments at 9.

#### Disposition

All commenters expressed support for the proposed clarifications regarding categorization of program expenses as administration versus incentives. This Phase IV approach will provide an accurate assessment of cost allocation requested by the Industrials. Therefore, EDC and CSP tracking and reporting expenses will continue to be treated as a TRC cost regardless of whether the labor, materials, and other fees are incurred by EDC staff, a CSP, or evaluation contractor. Kit and directly installed equipment costs will be treated as IMCs and incentives.

### Incremental Costs

The IMC of an EE&C plan measure varies by measure type and the assumptions about the baseline – or what costs the participant would have incurred absent program participation. Table 6, below, is adapted from the Pennsylvania Evaluation Framework[[70]](#footnote-71) and provides a useful summary of common measure types. It is important that the methodology used to compute incremental cost continue to be aligned with the methodology used to calculate energy savings.

Table 6: Incremental Cost by Measure Type

|  |  |  |
| --- | --- | --- |
| Type of Measure | Incremental Measure Cost ($/Unit) | Impact Measurement (kWh/Year/Unit) |
| New Construction | Cost of efficient device minus cost of baseline device | Consumption of baseline device minus consumption of efficient device |
| Replace on Burnout (ROB) | Cost of efficient device minus cost of baseline device | Consumption of baseline device minus consumption of efficient device |
| Retrofit:An additional piece of equipment or process is “retrofit” to an existing system. (e.g., additional insulation or duct sealing) | Cost of efficient device plus installation costs | Consumption of old device minus consumption of efficient device |
| Early Replacement: Replacement of existing functional equipment with new efficient equipment | Present value of efficient device (plus installation costs) minus present value of baseline device (plus installation costs) | *During remaining life of old device:* Consumption of old device minus consumption of efficient device*After remaining life of old device:* Consumption of baseline device minus consumption of efficient device |
| Early Retirement(No Replacement) | Cost of removing old device | Consumption of old device |

 In preparation for Phase II, we directed the Phase I SWE to complete an incremental cost database by December 31, 2012, to support EE&C plan development and uniform calculation of TRC costs across EDCs. *See 2013 TRC Test Order* at 25*.* We also recognized that an EDC’s EE&C plan may include measures that are not adequately addressed by the SWE incremental cost database or other industry resources. Since the initial development of the SWE’s incremental cost database, the SWE has conducted research to update cost assumptions for various measures. In the 2021 TRC Test Tentative Order, the Commission proposed to have the Phase IV SWE update the Incremental Cost Database by July 1, 2020.

Furthermore, the Commission proposed that the SWE incremental cost database remain an optional resource for EDCs and their evaluation contractors. EDCs may elect to use the cost assumptions in the incremental cost database or other reputable industry sources in their EE&C plans and annual TRC reporting. The source of all IMC assumptions should be documented. EDCs should use actual project costs where available and practicable (*e.g.*, retrofit projects).

#### Comments

Duquesne notes that the sentence that states “The Commission proposes to have the Phase IV SWE update the Incremental Cost Database by July 1, 2020” should state that the Commission proposes to have the Phase III SWE make the required update, or else suggests that the timeline for completing updates should be extended. Duquesne Comments at 4.

#### Disposition

Duquesne is correct that the 2021 TRC Test Tentative Order should have referred to the Phase III SWE on this point. We will direct the Phase III SWE Team to update the Incremental Cost Database by July 1, 2020.

### Act 129 Incentives

Incentives to program participants are a transfer payment intended to offset the IMC of efficient equipment. They are a cost to the EDC and a benefit to the participant, so they are neither a cost nor a benefit in the TRC Test. An exception to this rule occurs when the incentive amount is greater than the IMC. If the incentive amount is greater than the IMC, the incentive amount should be used as the TRC cost instead of the IMC. Incentives may be greater than the IMC when an EDC elects to make the efficient option the lowest cost option for participants (*e.g.*, discounting an LED lighting bulb in retail stores such that the upfront cost of the efficient LED is less than the cost of a comparable halogen or incandescent lamp). Incentives can also exceed incremental cost when there is no clear measure cost, such as for Appliance Recycling programs.

As discussed in Section D.1 Program Administration and Overhead, above, the Commission proposed for the 2021 TRC Test to categorize the cost of kits and directly installed equipment as an incentive to program participants. The labor cost to directly install equipment in homes and businesses should also be categorized as an incentive. In prior orders, we have defined an incentive as “a payment made to a program participant by an EDC to encourage the customer to participate in an energy efficiency program and to help offset some, or all, of the participant’s costs to purchase and install an energy efficiency measure.” *See 2013 TRC Test Order* at 16. Our position is that kits and directly installed equipment encourage customers to participate in programs and offset some or all the cost to install energy efficiency equipment. Kits and direct install programs do not require the participant to pay the upfront cost and then recover a portion of that cost via a second financial transaction with the EDC. This does not affect the underlying program mechanism whereby an EDC program reduces the participant cost for measure installation.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

As proposed in the 2021 TRC Test Tentative Order, we direct the EDCs to continue to treat incentive costs as neither a cost nor a benefit in the TRC Test, except when the incentive amount is greater than the IMC, in which case the incentive amount should be used as the TRC cost instead of the IMC. As discussed in Section D.1.b, kits and direct install programs will be treated as proposed in the 2021 TRC Test Tentative Order.

### Incentives from Outside of Act 129

In the TRC Test formulae for Phases I-III, outside incentives appear as the factor “*TCt*” or tax credits in year *t*. This term is counted towards the program benefits. In the 2021 TRC Test Order, the Commission proposed that it is more appropriate to consider incentives from outside of Act 129 as a reduction in costs, not as a benefit of the program. Also, since the outside incentives may be from sources other than tax credits, such as grants, the Commission proposed instead to use the term “*OIt*” or outside incentives in year *t* in the formulae. We anticipate that these changes to the formulae will not materially alter the outcome of the calculated B/C ratio, but the change is more representative of the source of non-Act 129 incentives. As noted in Section A.8 Measures Supported by Both Act 129 Programs and Other Funding Streams, above, EDCs only need to factor in, as reductions to cost, those non-Act 129 incentives that are reasonably quantifiable by the EDC. Stakeholders were encouraged to run existing values through the new formulae and comment if they noticed a material difference in outcomes.

The Commission interpreted “reasonably quantifiable” to include any non-Act 129 incentive, such as a rebate, tax credit, or grant, where the EDC has direct data on the amount of the incentive and the fact that the customer made use of the funds. For example, if a participant completes a $500,000 retrofit project and receives a $100,000 grant from outside funding sources, the EDC should include the $100,000 as a cost reduction and use $400,000 as the IMC. Federal tax credits to individuals for energy efficient equipment also supported by Act 129 incentives would be an example of an incentive that the Commission would consider not reasonably quantifiable. The EDC would not have a way of knowing if a given customer actually claimed the credit and what the actual impact was on their ultimate tax liability.

#### Comments

As described in the comments of section A.8, Measures Supported by Both Act 129 Programs and Other Funding Streams, OSBA holds that incentives from outside of Act 129 should not be considered an offset to incremental measure costs in the TRC Test. OSBA Comments at 9.

In reply comments, FirstEnergy states that excluding alternative revenue streams, including tax credits, is at odds with long-standing standard industry practice and that OSBA’s recommendation to exclude tax credits should be rejected. FirstEnergy Reply Comments at 2.

#### Disposition

As discussed in the disposition of Section A.8, Measures Supported by Both Act 129 Programs and Other Funding Streams, the treatment of outside incentives is a key distinguishing factor of the TRC Test from the Societal Cost Test. While we reserve the right to adapt aspects of the TRC Test to mirror the policy objectives of the Commonwealth, the Commission finds this suggestion inconsistent with the fundamental perspective of the TRC Test and rejects OSBA’s suggestion.

## Fuel Switching

### ENERGY STAR Requirement

In Phases I, II, and III, EDCs have been allowed to support fuel switching measures that convert equipment from electricity to fossil fuel, but the fossil fuel equipment must meet or exceed the current United States Environmental Protection Agency (EPA) minimum ENERGY STAR performance standard. We saw no reason to change this minimum efficiency provision for Phase IV. The 2021 TRM includes several fuel switching measures with algorithms and assumptions that reflect this ENERGY STAR minimum performance standard.

However, if an EDC proposes a fuel switching measure for which there is no ENERGY STAR performance standard, the Commission’s proposal in the 2021 TRC Test Tentative Order is that the EE&C plan should state a proposed minimum standard and provide justification for the threshold. For example, if an EE&C plan includes CHP systems as a measure, the EE&C plan should specify the minimum thermal efficiency to receive program support. This would represent a change from the 2016 TRC Test Order.

#### Comments

OCA agrees that the proposed change for situations in which there is no ENERGY STAR performance standard is appropriate and suggests that it may be beneficial to develop a template for evaluating a proposed minimum standard to ensure that all relevant data has been provided and that the level of detail provided is consistent across the EDCs’ proposals. OCA Comments at 7.

PA-EEFA comments that, in light of any relevant climate initiatives or directives from the Governor or Legislature, the Commission should review the merits of allowing utilities to promote fuel-switching from electricity to fossil fuel for Phase IV. PA-EEFA states that in the development of the utilities’ program plans, all cost-effective alternatives to fuel-switching should be evaluated both for the economic benefits they can provide compared with fuel-switching and for their ability to provide meaningful impacts in the pursuit of climate goals. PA-EEFA Comments at 9-10.

#### Disposition

We agree with OCA that selection of minimum performance standards for fuel switching measures is an important consideration. Keeping in mind the tradeoffs between EDC program design flexibility and the desire for consistency across EDCs, we will include some degree of guidance on this issue in the Secretarial Letter proposing the Phase IV EE&C Plan Template.

The Commission is aware of initiatives in other states to pursue “beneficial electrification” where conversions from fossil fuel to electricity are promoted as opposed to electricity to fossil fuel. Given the current generation mix in Pennsylvania, we find that that promotion of high efficiency natural gas measures is beneficial to program participants, non-participating ratepayers, and the Commonwealth’s climate goals. We will continue to monitor the issue raised by PA-EEFA to determine if promotion of fuel switching measures within Act 129 should be reconsidered in future phases.

### Increased Fuel Consumption

In Phase III, increased fuel consumption was treated as a TRC cost. The Commission proposed in the 2021 TRC Test Tentative Order that increased fuel consumption from fuel switching would be treated as a negative TRC benefit in the 2021 TRC Test. Fuel consumption offset by the installed equipment, such as CHP, should be estimated to calculate the net change in fuel consumption from fuel switching. This can lead to a positive or negative TRC benefit. CHP equipment that reduces existing natural gas consumption more than the fuel it consumes provides a positive fuel TRC benefit in cases such as CHP replacing inefficient boilers or CHP offsetting steam purchased from a third-party source.

The Commission proposed that the marginal system cost of the fuel would continue to be used to monetize the projected fuel consumption over time if the fuel consumed is natural gas. The forecast methodology for natural gas is outlined in Section C.5 Monetizing Fossil Fuel Impacts, above. The retail cost should be used for delivered fuels, such as gasoline or propane, and the estimated production cost should be used for on-site fuels, such as biogas.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

We therefore direct the EDCs to treat increased fuel consumption from fuel switching as a negative TRC benefit in the 2021 TRC Test.

## Net-to-Gross (NTG) Issues

### Use of NTG Research

In the 2016 TRC Test Order, the Commission required that EDCs report TRC Test ratios in Phase III EE&C plans in two ways: (1) based on projected gross savings and (2) based on projected net savings. *See 2016 TRC Test Order* at 46-47. In the 2021 TRC Test Tentative Order, the Commission proposed no changes to this requirement for Phase IV. EDC evaluation contractors would continue to conduct NTG research, use the results for program planning purposes, report net verified savings, and calculate the TRC Test results on a net basis.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

Therefore, we direct EDCs to continue to report TRC Test ratios in Phase IV EE&C plans based on both projected gross savings and projected net savings.

### Treatment of Incentives to Free-Riders

In the 2021 TRC Test Tentative Order, the Commission proposed to maintain the current Phase III position on the treatment of incentives for free-riders for Phase IV, which is that free-rider incentives shall not be included as an additional program cost when considering a net TRC Test perspective and to continue to account for other program costs. NTG research would be considered only for the purposes of program planning. Free-rider participant costs would have occurred even in the absence of a program and are not part of net program costs.

Spillover, the opposite of the free-rider effect, occurs when customers adopt measures because they are influenced by program-related information and marketing efforts, but these customers do not actually participate in the program. Consequently, the participant costs are reduced by the NTG value.

The Commission is aware that the inclusion of costs for incentives for free-riders in the calculation of a TRC Test was addressed by the California Public Utilities Commission in the *2007 Clarification Memo.*[[71]](#footnote-72)In the 2016 TRC Test Order, the California clarification to include free-rider incentives as a program cost was, however, rejected. We concluded that, for use in the Commonwealth, the California clarification would overstate TRC costs and contradict the underlying rationale of our TRC Test perspective, which ignores incentive payments as transfer between program and participant.

#### Comments

OSBA does not contest the Commission’s exclusion of incentives for free-riders from costs in the NTG-adjusted 2021 TRC Test but encourages the Commission to scrutinize programs with relatively low NTG ratios to ensure that EE&C programs are achieving net benefits that would not be achieved in the absence of the programs. OSBA Comments at 14.

#### Disposition

We agree with OSBA regarding the need to scrutinize programs with low NTG ratios. When EDCs conduct NTG research for program planning purposes, one of the key outcomes the Commission expects EDCs and their evaluators to consider is market transformation, and more specifically, the point in time at which free-ridership rates indicate that the efficient technology has become the market standard and no longer warrants Act 129 program support. Free-ridership and spillover shall continue to be factored into the calculation of TRC benefits and costs by comparing the benefits and costs of a program with what the savings and costs would have been in the absence of the program

### Treatment of NTG for TRC Benefits

In the 2021 TRC Test Tentative Order, the Commission proposed no changes to the treatment of NTG for TRC benefits but reminded EDCs that NTG ratios would be applied to all benefits in the 2021 TRC Test. The benefits would include, but would not be limited to, avoided energy and capacity costs, O&M, interactive effects, and secondary fossil fuel impacts. NTG research would only be applied to the 2021 TRC Test for the purposes of reporting and program planning. EE&C plans would not be required to be cost-effective on a net basis.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

The Commission’s proposed treatment of NTG ratios for the calculation of TRC Benefits will continue for Phase IV. NTG ratios will be applied to all benefits in the net TRC Test and NTG research will only be applied to the 2021 TRC Test for the purposes of reporting and program planning.

## Demand Response

### DR Testing if DR Is Included in Phase IV

The Commission has not yet determined DR (or EE) targets for the potential Phase IV. At this time, we expect the Phase III SWE’s DR Potential Study to be released in early 2020. The results of that analysis will inform our decision relative to a Phase IV. If it is determined to proceed with a Phase IV, we anticipate that we will enter a Phase IV Implementation Tentative Order in spring 2020 and a Final Implementation Order in summer 2020. In the 2021 TRC Test Tentative Order, stakeholders were encouraged to comment on the proposed cost-effectiveness methodology for DR and refrain from commenting on issues related to whether DR should be included in or excluded from a potential Phase IV.

#### Comments

AEMA states the Act 129 Phase IV 2021 TRC Test and related DR Potential Studies should consider all customer classes and technologies that drive peak demand reduction, and that other states such as Massachusetts have adopted programs that offer two levels of participation to customers – daily dispatch and infrequent dispatch – to capture different willingness to curtail across different customer types. AEMA also notes that electric vehicle charging was not considered in Phase III but should be considered for Phase IV. AEMA Comments at 6-7.

#### Disposition

The Commission has made no determination regarding whether there will be a Phase IV and if so whether the Phase IV programs will include demand response targets. We have requested the Phase III SWE to consider behind-the-meter battery storage as an emerging DR technology in the MPS. Additionally, should Phase IV include demand response targets, the Commission has made no determination regarding the frequency, duration, or notification time of demand response events, nor have we determined which PJM DR mechanism, if any, a potential DR program may be designed around. We expect the SWE’s Phase IV DR MPS to include a recommendation on these issues as these assumptions have significant impacts on the amount of demand response potential in an EDC service territory and the cost to acquire it.

### Calculation of TRC Benefits

DR programs are designed to reduce peak demand, so the dominant benefit streams are the avoided cost of generation, transmission, and distribution capacity on a $/kW-year basis. As we discussed in the 2016 TRC Test Order, DR program designs will invariably result in a variable number of DR dispatch hours each program year. *See 2016 TRC Test Order* at 52.

In the 2021 TRC Test Tentative Order, we proposed that EDCs average the gross verified demand reductions over each hour of performance and apply a line loss adjustment factor to estimate the magnitude of the peak demand reduced. This demand reduction value would be multiplied by either two or three avoided cost-of-capacity values, depending on customer sector.

In Phase III, peak demand reductions were assigned the full avoided cost of generation capacity. This assumption was flagged for further investigation in the SWE Program Year 9 Annual Report,[[72]](#footnote-73) which stated:

The 2016 TRC [Test] Order assumes a 1:1 reduction in avoided generation capacity for the average MW reduction each program year. This planning assumption now appears to be overstated based on discussions in PJM’s Summer-Only Demand Response Senior Task Force.9 Modeling efforts by PJM indicate that 1 MW of summer peak shaving from programs like Act 129 produce a less than 1 MW reduction in the peak load forecast and zonal capacity obligations. While consistent with the 2016 TRC [Test] Order, the TRC benefits from the avoided cost of generation capacity likely overstate the true benefit to the Commonwealth.

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9 *See* <https://www.pjm.com/committees-and-groups/task-forces/sodrstf.aspx>.

The Commission proposed that Phase IV DR programs, if any, should be nominated to PJM as Peak Shaving Adjustments (PSAs). This position was a departure from the Phase III DR design which did not formally nominate resources to PJM, but instead relied on reductions to have a downward influence on PJM’s zonal peak load forecasts. The Commission recognized that Price Responsive Demand (PRD),[[73]](#footnote-74) where customers can control their electric energy expenditures by changing their electric usage in response to wholesale electricity prices, is another potential avenue for Act 129 DR programs to be recognized at PJM. However, based upon input from the Phase III SWE, we initially proposed the PSA mechanism may be the most appropriate path. However, we are not making a DR program implementation design decision in this TRC Order. Stakeholders were encouraged to provide comments on the proposal to nominate Phase IV Act 129 DR program reductions as PSAs as opposed to other DR programs or the Phase III design where Act 129 DR is not formally nominated to PJM. PSAs and PRD treat summer DR as a demand resource, rather than a supply resource, and lower the zonal peak load forecast and capacity obligation of a zone – which benefits all ratepayers. Load forecast reductions for the PSAs are not a 1:1 ratio to the amount of peak shaving, whereas PRD adjustments for summer peaking customers can be a 1:1 ratio to the amount of peak shaving. The exact reduction for PSAs will depend on the frequency and timing of the peak shaving activity, as well as the load characteristics of the zone.

No Pennsylvania EDC nominated peak shaving in preparation for the 2022/2023 BRA. Baltimore Gas and Electric (BGE) was the only PJM entity to nominate peak shaving. The Phase III SWE provided PJM with hypothetical Pennsylvania data for analysis, but the results were not available for inclusion in the 2021 TRC Test Tentative Order.

Without Pennsylvania-specific data, we chose to review the BGE data. Table 7 compares the non-coincident and coincident peak load forecasts for BGE zone in the January 2019 Load Forecast Report[[74]](#footnote-75) to the data in the March 2019 Load Forecast Report.[[75]](#footnote-76) The difference between the two forecast reports is the inclusion of the PSA for BGE zone. BGE nominated 390 MW of peak shaving, which factors in as an adjustment in Table 7.

Table 7: Summer Peak Load Forecast Impacts from BGE PSA



The 390 MW peak shaving commitment by BGE resulted in an average reduction in the coincident summer peak demand forecast of 233 MW, or 60% of the nominated quantity of peak shaving. The reduction in the non-coincident peak load forecast[[76]](#footnote-77) is lower, but our conclusion is that the coincident peak demand forecast[[77]](#footnote-78) impacts are the relevant metric for capacity obligation and valuation of DR.

Based on this preliminary analysis of the BGE data, the Commission proposed that EDCs use 60% of the avoided cost of generation capacity for a program year to monetize DR impacts.

In the 2021 TRC Test Tentative Order, we proposed that a similar perspective was appropriate for the avoided cost of T&D capacity from DR programs for several reasons.

* Individual transmission areas or networks on the distribution system may not peak at the same time as the entirety of the PJM system. If peak shaving activities target system peak hours, they will not necessarily provide the load relief needed to avoid or defer capital upgrades to T&D infrastructure.
* DR participation can be uneven and hard to forecast. Avoided T&D benefits are inherently localized, and DR participation in areas with constraints may not be aligned with territory average.
* Act 129 planning is cyclical, with targets and plans established in three- to five-year phases. EDC system planners are tasked with ensuring long-term reliability and may “discount” Act 129 peak demand reductions as temporary and be reluctant to count on DR to avoid or defer capital upgrades.

Based on these considerations, we proposed a similar 60% assumption be applied to avoided T&D benefits from DR. If an EDC’s avoided cost of transmission capacity as shown in Table 1 were $20/kW-year, a value of 0.6\*20 = $12/kW-year should be used to calculate the avoided cost of transmission capacity from DR programs.

As in Phase III, the Commission proposed in the 2021 TRC Test Tentative Order that any peak demand reductions achieved by DR participation from the Residential and Small C&I sectors should be multiplied by an avoided cost of distribution capacity ($/kW-year). The values as shown in Table 2 of this Order would be discounted by a multiplier of 60%. As in Phase III, we proposed that any peak demand impacts from DR participation by Large C&I customers receive no avoided cost of distribution capacity benefit because Large C&I accounts receive service at primary voltage and largely bypass the distribution system. As such, DR impacts achieved by this sector would be presumed unlikely to avoid or defer load growth related investments in an EDC distribution system. *See 2016 TRC Test Order* at 53.

#### Comments

With respect to the PSA, EAP requests that (1) the proposed methodology for determining the cost-effectiveness of DR not be used by the SWE in connection with the market potential and demand response potential studies currently underway to determine Phase IV targets; (2) in lieu of mandatory demand reduction targets, voluntary DR pilot program(s) would allow stakeholders to gain experience with the proposed PSA program and determine whether it will lead to a cost-effective load reduction methodology suitable for inclusion in Phase IV and beyond; and (3) to the extent demand reduction targets are mandated for the next phase, EDCs should not be required to nominate Phase IV Act 129 DR program reductions to PJM as PSAs. EAP contends that the proposed approach unnecessarily exposes the EDCs to an unacceptable degree of risk where, *inter alia*, the mandated target must be met precisely and the statute provides no leeway or discretion for the Commission to consider whether an EDC used best and/or reasonable efforts to achieve reductions in consumption and/or demand. EAP Comments at 3-4.

In support of its position, EAP comments that (a) the PSA is new and unproven and should not be the basis for valuing DR benefits in a potential Phase IV DR program; (b) use of the PSA may not be a cost-effective use of ratepayer funds as compared to other cost-effective Act 129 program options; (c) nomination of DR resources to the PSA program will not be possible for the entire potential Act 129 Phase IV; and (d) the PSA program would negatively impact the willingness of eligible customers to participate in Act 129 DR programs. EAP Comments at 5-10.

With respect to the benefits stream from the avoided costs of generation, transmission, and distribution, EAP avers that using sixty percent of the avoided cost of capacity for all programs is not reasonable because the avoided cost of capacity for each nomination of DR resources into the PJM PSA program will be largely dependent on DR program design elements, such as the Temperature Humidity Index (THI) threshold. EAP also avers that using the PSA forecasted by BGE as the proxy for avoided costs in Pennsylvania is unreasonable because it is not supported by any details or analysis concerning the BGE program that would allow for evaluation or comparison to current Act 129 DR program criteria or for comparison of its use and applicability in Pennsylvania. Lastly, EAP opposes the use of any T&D avoided costs for DR program valuation under any program design that does not to target specific T&D growth or peak system related issues. EAP Comments at 11-12.

PPL states that it agrees with and supports the Comments by the EAP. PPL Comments at 2.

Duquesne states that it generally supports the positions articulated in EAP’s comments, to the extent they are consistent with its own comments, and highlights issues raised by EAP to suggest that a DR program be an optional component of an EDC’s EE&C plan. In particular, Duquesne states that the PSA is new and untested and should not be the sole avenue for testing cost-effectiveness of a DR program; the timeframe for participation in the PSA does not align with the timing of a potential Phase IV; and the prohibition on dual enrollment in both PJM’s DR and PSA programs will limit the pool of potential DR participants for Phase IV because customers will choose to stay in PJM’s DR program. Duquesne Comments at 1 and 5.

AEMA points out similar issues, namely that PJM capacity procurement and Act 129 planning processes are incongruent and the prohibition on dual enrollment in both PJM’s DR and PSA programs will limit the pool of potential DR participants for Phase IV because commercial and industrial customers are more likely to choose to enroll in PJM’s DR programs rather than Act 129 programs. AEMA recommends that the Commission still consider residential participation in the PSA (or PRD) but not require commercial and industrial customer participation to participate via the PSA (or PRD). AEMA states that the Commission should update its capacity value for C&I curtailment without the PSA based on input from PJM regarding the normal downward pressure on zonal obligations of curtailment at peak times. AEMA Comments at 2-6.

KEEA states that the proposed sixty percent multiplier for the cost of generation capacity is insufficiently supported by the evidence and that this multiplier risks significantly underestimating the value of demand response. KEEA comments that the Commission should consider the inclusion of additional Pennsylvania-specific proxies to draw conclusions about the impact of DR nominations on peak load forecasts. KEEA Comments at 4.

OCA states that there is not enough data to warrant the proposed changes at this time and that it is premature to decide whether an EDC should be required to nominate its DR as PSAs. OCA requests that the Commission allow for comments once the results of the Pennsylvania PJM analysis have been completed to determine whether EDCs should be required to participate in the Peak Shaving market, and only at this point should the parameters for monetization of avoided capacity costs (*i.e.*, sixty percent) be considered. OCA Comments at 7-9.

In reply comments, Duquesne supports EAP’s position and notes that entities with diverse interests expressed similar sentiments regarding the use of the PSA. Duquesne reiterates its initial comments that the PSA program is new and untested, and thus a decision about its use for a potential Phase IV is premature. Duquesne Reply Comments at 1-2.

In reply comments, EAP notes that other parties agree that the 2021 TRC Test should neither require EDCs to nominate potential Phase IV DR programs PSAs nor adopt the proposed methodology to monetize DR impacts and emphasizes the need for additional consideration and input prior to making a final determination. EAP Reply Comments at 2-4.

In reply comments, the Industrials state that they share some of the concerns articulated by the EAP, and that EE&C plans should not include measures for DR or EE that are already adequately incentivized by and available in the wholesale and retail markets. The Industrials additionally state that they agree with OCA and AEMA that determinations regarding DR should be made after the SWE releases its DR potential study. Industrials Reply Comments at 2-3.

In additional reply comments, EAP also recommends the rejection of AEMA’s suggestion to require the nomination of potential Phase IV DR programs for residential programs only to PJM as PSAs and reiterates its initial set of reply comments that EDCs should not be mandated to nominate Phase IV DR programs for any class of customers. EAP Additional Reply Comments at 2.

#### Disposition

The Commission agrees with parties who expressed concerns regarding the application of PSA results from BGE zone to Pennsylvania EDCs. To make the valuation of generation capacity impacts more specific to Pennsylvania, the Commission, in collaboration with the Phase III SWE, requested PJM’s load forecasting group model the coincident and non-coincident summer peak demand forecast impacts of a hypothetical Phase IV demand response program. The program design characteristics are based on simulations conducted by the Phase III SWE in preparation for the DR market potential study. The hypothetical program design is assumed to be active non-holiday weekdays June-September hours ending 16, 17, and 18 (*i.e.,* 3pm to 6pm). Table 8 presents the size and THI trigger for the hypothetical design by EDC. The program size was set to be generally proportionate to Phase III goals except for Penelec, which does not have a Phase III demand response target. The THI thresholds were established to balance expected forecast impact with event frequency. EDCs with warmer service territories would trigger DR at a higher THI than EDCs with milder weather patterns. Table 8 also shows the average number of events that would have been triggered at the THI threshold using historic weather data for each zone.

Table 8: DR Program Characteristics for PJM Analysis[[78]](#footnote-79)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Zone | EDC | MW | THI Trigger | Average # Events (1998-2018) |
| APS | West Penn Power | 75 | 80 | 8.00 |
| ATSI | Penn Power | 15 | 80 | 8.31 |
| DQE | Duquesne Light | 50 | 80 | 7.77 |
| METED | Met-Ed | 50 | 82 | 7.23 |
| PECO | PECO | 150 | 82.5 | 7.38 |
| PL | PPL | 100 | 81 | 7.31 |
| PENLC | Penelec | 50 | 79.5 | 7.69 |

Table 9 shows the results of PJM’s analysis. Forecast reductions are expressed in percentages. For example, if an EDC’s hypothetical DR program were 50 MW and PJM’s forecast sensitivity indicated that the program would lower the peak demand forecast by 30 MW, the percent impact would be 30/50 = 60%. These values represent the de-rating factor discussed in the 2021 TRC Test Tentative Order for the avoided cost of generation capacity.

Table 9: Results of PJM PSA Sensitivity Analysis[[79]](#footnote-80)

|  |  |  |
| --- | --- | --- |
| EDC | Impact on Non-Coincident Peak | Impact on Coincident Peak |
| West Penn Power | 69.1% | 77.7% |
| Penn Power | 59.0% | 13.8% |
| Duquesne Light | 43.5% | 78.0% |
| Met-Ed | 25.2% | 46.5% |
| PECO | 45.5% | 45.8% |
| PPL | 37.1% | 70.4% |
| Penelec | 6.0% | 70.0% |
| Weighted Average | **41.5%** | **60.6%** |

While the weighted average impact on the coincident peak demand forecast statewide is very close to the 60% value proposed in the 2021 TRC Test Tentative Order, the Commission notes the considerable variation across EDCs. Therefore, EDCs should use the “impact on coincident peak” values in Table 9 to de-rate the avoided cost of generation capacity from Phase IV demand response programs, whether offered as PSAs or under a Phase III design where Act 129 DR is not formally recognized by PJM. The Commission retains the flexibility to apply a different valuation, which may apply to other DR programs.

We disagree with EAP’s suggestion that T&D benefits be excluded entirely from the calculation of demand response benefits for DR programs that do not target specific T&D growth. DR programs that target specific areas to avoid or defer capital investments would have higher T&D benefits than the system-wide average, but a mass market DR program not targeting specific areas would still experience participation in constrained areas.

The sensitivity analysis conducted by PJM’s load forecasting group provides valuable EDC-specific insights into the valuation of Act 129 demand response on generation capacity obligations. However, we find that these results are not directly transferrable to demand response on T&D and direct all EDCs to use the 60% factor set forth in the 2021 TRC Test Tentative Order when valuing the avoided cost of T&D capacity benefits of Phase IV demand response.

Several of EAP, OCA, and AEMA’s comments deal with the uncertainty and administrative timing challenges of the PSA mechanism. Each of the issues identified by commenters are important considerations, and the Commission has been exploring these issues carefully with the Phase III SWE in coordination with the Phase IV DR potential study. We appreciate the insightful points raised and look forward to continued discussions about the appropriate construct of DR in Phase IV, if any, during the DR MPS stakeholder meeting and as part of a Phase IV Implementation proceeding.

### Participant Cost Assumption

As established in Phase I, customer incentives in a DR program are intended to compensate participants for the sacrifices they make to consume less electricity during peak periods. Such sacrifices can take the form of being less comfortable in the case of a residential Direct Load Control (DLC) program or a disruption in production for a business that shuts down a manufacturing process. In recognition of these sacrifices, we directed EDCs in Phase I to include the full incentive payment amount as a cost to the participant as a monetary proxy for participant costs. *See 2011 TRC Test Order* at 13‑14. There were no DR requirements in Phase II.

In the 2016 TRC Test Order, we explored how using 100% of the incentive amount could be problematic and yield skewed TRC Test results because it assumes that participation in a DR program is a “break-even” arrangement for the participant, where the benefits are identical to the costs. We rejected the break-even assumption, instead adopting the perspective that customers are generally rational and would likely only participate in a DR program if they felt the benefits of participation outweighed the costs.

As a result, for Phase III, we adopted the 75% participant cost assumption set forth in California’s 2010 DR Cost-Effectiveness Protocols[[80]](#footnote-81) as a solution. Under this protocol, 75% of the customer incentive payment is used as a proxy for the participant cost when calculating the TRC Test ratio for DR programs. We recognized that many EDCs would elect to use CSPs to implement DR programs and that the exact incentive payment from the CSP to the participant might therefore be unknown. We, therefore, directed EDCs to use 75% of the payment amount to the CSPs as a cost in the 2016 TRC Test for Phase III.

We proposed no changes in the 2021 TRC Test Tentative Order regarding the use of DR incentive amounts to estimate participant costs for Phase IV. EDCs would continue to use the 75% participant cost assumption.

#### Comments

Stakeholders did not comment on this topic.

#### Disposition

For the 2021 TRC Test, EDCs are directed to continue to use the 75% participant cost assumption as discussed above.

### Measure Life

DR is a broad category of programs and measures that may or may not involve equipment installed at the participating customer’s location. For load curtailment programs, participation involves a financial incentive between the EDC, or its CSP, and the program participant. As specified in the 2021 TRM, the measure life for load curtailment programs is one year. The 2021 TRM provides that the measure life of behavioral DR programs, which include neither incentives nor equipment, will be assumed to be one year.

For DR programs where the utility pays some or all the cost of DR equipment, the 2021 TRM provides that the mechanical life of the equipment must be considered. Examples of DR equipment include a Wi-Fi-connected “smart” thermostat, a water heater or air conditioner cycling switch, a battery, an electric vehicle charger that the EDC can control, and other similar equipment that the EDC (or CSP) can control. For this class of DR programs, we proposed in the 2021 TRC Test Tentative Order that a measure life equivalent to the expected mechanical life of the equipment is appropriate.

When a multi-year measure life is assumed for DR, consistent with the 2016 TRC Test requirements, we proposed EDC also account for expected incentive costs over the measure life. For example, in a traditional air conditioner cycling program, where the EDC (1) purchases and installs the DLC equipment and (2) pays the participant $50 per summer in exchange for continued participation in the program, the annual $50 must be factored in. In order to realize the multi-year benefits of the equipment, annual costs are incurred. If a ten-year measure life is applied to the load control equipment when calculating benefits, ten years of assumed incentive costs should also be factored in. We did not propose a change to this provision for the 2021 TRC Test.

We also reminded the EDCs that any DR equipment purchased in a previous phase cannot be included in the 2021 TRC Test for Phase IV. Those expenses were accounted for as costs in a previous TRC Test and to consider them as TRC Test costs again would be “double-counting.”

#### Comments

FirstEnergy states that the Commission should assume a measure life equivalent to the length of Phase IV, not the expected lifetime of the device as proposed, because (i) there is no certainty the demand response measure will generate demand reductions for its expected life; and (ii) there is no certainty the Commission will establish demand response targets for future phases of Act 129. FirstEnergy states that this approach would most reasonably balance the uncertainty inherent to this issue. FirstEnergy Comments at 4-5.

#### Disposition

The Commission agrees with the points raised by FirstEnergy regarding the uncertainty of a device providing demand reductions in future phases. Therefore, for Phase IV, the measure life of direct load control equipment should be equivalent to the remaining length of the phase. This approach is consistent with the modeling framework used by the Phase III SWE for Wi-Fi connected thermostats in the Phase IV DR MPS.

## Additional Matters

Several parties raised issues that do not map directly to sections of the 2021 TRC Test Tentative Order. We shall address each in turn. All parties had the opportunity to address these matters in reply comments if they wished to do so.

### 1. Applicability of NSPM to the Act 129 TRC Test

The Joint Intervenors suggest the Commission commence a process that applies the NSPM to the 2021 TRC Test and stress the importance of getting cost-effectiveness testing “right” in a budget-constrained framework. Joint Intervenors Comments at 4.

In reply comments, the Industrials state that the Joint Intervenors’ suggestion that the Commission “test the test” through the NSPM is inappropriate and unnecessary because the NSPM’s policies and goals are not part of the Pennsylvania statute. Industrials Reply Comments at 8.

**Resolution** – Following the release of the NSPM in 2017, the Commission tasked the Phase III SWE with a detailed review of the NSPM and an inventory of how the 2016 TRC Test Order compared with the principles outlined in the NSPM. Many of the issues identified by the Phase III SWE as part of the NSPM review were instrumental in guiding our proposals in the 2021 TRC Test Tentative Order. The 2017 NSPM review did not include a comprehensive review of Commonwealth policies, laws, and regulations. We reject the suggestion to “pause” the 2021 TRC Test Order for an additional NSPM review. We do, however, agree that such a review could be considered an initial step in the preparation of future Act 129 TRC Test Orders.

### 2. Creation of an Energy Efficiency Technical Advisory Committee

In reply comments, BPA notes that the DR market is expected to grow in upcoming years and suggests that the Commission establish an energy efficiency technical advisory committee to develop positions and recommendations on technical issues related to EE and DR. BPA Reply Comments at 2-4.

**Resolution –** Atthis point in time, the Commission does not see the need to create an additional advisory committee on EE and DR as part of TRC Test consideration. Concerns related to an EE technical advisory committee should be raised in the context of Docket No. M-2019-3006867.

### 3. Demand Response Requirements by Utility

AEMA suggests the Commission consider a “Cap and Trade” approach to demand response targets where EDCs can either deliver their obligation directly or buy the resources from elsewhere in the state. AEMA Comments at 7-8.

**Resolution** – A “Cap and Trade” approach to EDC compliance targets is not something the Commission has considered previously in this context. If such a framework were considered for DR, we question whether it should also be considered for EE. As acknowledged in AEMA’s comments, there are inherent challenges with this approach, but we appreciate stakeholders presenting innovative ideas and will take the suggestion under advisement when reviewing the SWE’s Phase IV DR MPS and deliberating how the results should be applied in the Phase IV Tentative Implementation Order. The TRC Test proceedings are not the appropriate forum in which to commence a Cap and Trade discussion.

### 4. Formula Error in Appendix A

PPL recommends the Commission revise the formula for TRC Benefitsgross in Table 12. PPL suggests that capacity benefits DBt were inadvertently omitted from the formula and should be added. PPL Comments at 2-3.

**Resolution** – PPL is correct that this omission was inadvertent and that capacity benefits are an important component of TRC benefits. We have updated the formula in Appendix A of this Order to reflect the corrected formula.

# CONCLUSION

With this Final Order, the Commission adopts the 2021 TRC Test for use in planning and evaluating the potential Phase IV of Act 129. All stakeholder comments and reply comments have been duly considered. Any issues raised by stakeholders that have not been addressed herein are deemed denied.

This Final Order, the 2021 TRC Test Tentative Order, and all filed comments and reply comments related to this Order will be available to the public on the Commission’s Act 129 Information web page[[81]](#footnote-82); **THEREFORE,**

**IT IS ORDERED:**

1. That the 2021 Pennsylvania Total Resource Cost Test be used for evaluating energy efficiency and conservation programs during Phase IV of Act 129, if implemented, consistent with this Order.
2. That a copy of this Order be served on the Office of Consumer Advocate, the Office of Small Business Advocate, the Commission’s Bureau of Investigation and Enforcement, all jurisdictional electric distribution companies subject to the Energy Efficiency and Conservation Program requirements, all parties who commented on the 2016 TRC Test Order at Docket No. M-2015-2468992, and all parties who commented on the 2021 TRC Test Tentative Order at this docket.

 3. That the Secretary shall deposit a notice of this Order with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

 4. That this Order be published on the Commission’s website at <http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/total_resource_cost_test.aspx>.

5. That the contact person for technical issues related to this Order and the 2021 Total Resource Cost Test for the potential Phase IV of Act 129 is David Edinger, Bureau of Technical Utility Services, 717-787-3512 or dedinger@pa.gov. The contact person for legal and process issues related to this Order and the 2021 Total Resource Cost Test for the potential Phase IV of Act 129 is Louise Fink Smith, Law Bureau, finksmith@pa.gov.

**BY THE COMMISSION**

Rosemary Chiavetta

Secretary

(SEAL)

ORDER ADOPTED: December 19, 2019

ORDER ENTERED: December 19, 2019

# Appendix A

The definitions and formulae to be used for the

Pennsylvania-specific 2021 TRC Test, consistent with Act 129 of 2008,

are set forth in this Appendix A.

**TRC Formulae, Calculations, and their Definitions**

 Table 10 below lists electricity supply avoided costs, other TRC benefits, TRC costs, and other assumptions, and it summarizes TRC guidance for each TRC element. Formulae are detailed for each TRC element in the algorithms section. These are split into primary and supporting algorithms, where the supporting algorithms assist with the calculation of input values required for implementing the primary algorithms.

Table 10: Definition of Terms

| **TRC Category** | **TRC Element** | **Units** | **Symbol** | **Guidance Summary** |
| --- | --- | --- | --- | --- |
| Avoided Costs of Supplying Electricity | Line losses | Unitless | $$LLF$$ | Table 1-4 of the 2021 TRM provides line loss factors by EDC and customer class. |
| Electric energy (quantity) | kWh/year | $$E$$ | Gross verified annual kWh. |
| Electric energy (price) | $/kWh (nominal) | $$MCE$$ | Twenty-year forecast divided into years 1-4, 5-10, 11-20. *See* supporting MS-Excel spreadsheet calculation model. |
| G, T, D capacity (quantity) | kW/year | $$D$$ | Gross or net verified peak demand savings (kW). |
| Generation capacity (price) | $/kW-year | $$MCD\_{t}$$ | Actual and escalated PJM BRA clearing prices. Apply 60% factor for DR programs. |
| Transmission capacity (price) | *See* Table 1. Apply 60% factor for DR programs. |
| Distribution capacity (price) | *See* Table 2. Apply 60% factor for DR programs. Does not apply to Large C&I. |
| Compliance with RPS/AEPS | $/kWh (nominal) | $$AEPS$$ | Electricity cost adder to reflect avoided compliance costs. |
| Other TRC Benefits | Water impacts (quantity) | Gallons | $$H2O$$ | Savings are positive. Increased water consumption is negative.  |
| Marginal cost of water (price) | $/gallon (nominal) | $$MCH2O$$ | $0.01 / gal (2021 dollars), escalated and inflated. |
| Fossil Fuel Impacts (quantity) | Therms/year | $$F\_{impact}$$ | Direct changes in fuel usage. Savings are positive, increases in fuel usage are negative.  |
| Marginal cost of fuel (price) | $/Therm (nominal) | $$MCF$$ | Twenty-year forecast divided into years 1-4, 5-10, 11-20. *See* supporting MS-Excel spreadsheet calculation model.Apply electric loss factors, by customer class. |
| Interactive Fuel Effects (Waste Heat) | Therms/year | $$F\_{waste}$$ | Secondary fuel impacts due to reduced waste heat from efficient lighting. Increased fuel usage recorded as a positive value. |
| Societal Benefits |  |  | Do not include. |
| O&M Benefits | $ or $/year (nominal) | $$O\&M$$ | Incremental relative to baseline equipment. Note some measures (CHP) can produce negative O&M benefits. |
| TRC Costs | Program Admin & Overhead | $(nominal) | $$PA$$ | Allocated to specific programs where applicable. Common costs can be allocated to programs or incorporated at the portfolio level. |
| Incremental costs | $(nominal) | $$IMC$$ | Maximum of IMC (relative to baseline) and incentive. *See* Table 6. IMC for DR programs assumed to be 75% of incentives. |
| Incentives from Outside Act 129 | $(nominal) | $$OI$$ | Incentives from outside of Act 129 considered as a reduction in costs, not as a benefit of the program. |
| Other Assumptions | Real discount rate | Unitless | $$r$$ | 3% |
| Nominal discount rate | Unitless | $$d$$ | 5% |
| Inflation rate | Unitless | $$inf$$ | 2% |
| Escalation rate | Unitless |  | Growth in real dollars. Based on CAGR of BLS GTD sector price index (NAICS 221110).  |
| Electric Line Loss Factor | Unitless | *LLFelec* | Varies by EDC and sector. *See* Tables 1-4 of the 2021 TRM |
| Gas Loss Factor | Unitless | *LLFgas* | 1.04167 |
| Water Loss Factor | Unitless | *LLFH2O* | 1.32 |
| Measure life | Years | $$N$$ | Maximum 15 years.For DR programs, lifetime of hardware. One-year lifetime for behavioral DR and load curtailment. |
| Free-ridership | Unitless | FR | Determined by evaluation contractor. |
| Spillover | Unitless | SO | Determined by evaluation contractor. |
| Market Effects (ME) | Unitless | ME | Determined by evaluation contractor. |
| Calculated Inputs | NTG Ratio | Unitless | NTGR | *See* Table 12. |
| Gross TRC benefits | $ | $$TRC Benefits\_{gross}$$ | *See* Table 12. |
| Gross TRC costs | $$TRC Costs\_{gross}$$ | *See* Table 12. |
| Net TRC benefits | $$TRC Benefits\_{net}$$ | *See* Table 12. |
| Net TRC costs | $$TRC Costs\_{net}$$ | *See* Table 12. |
| Electric energy benefits | $$ EB\_{t}$$ | *See* Table 12. |
| Capacity benefits | $$ DB\_{t}$$ | *See* Table 12. |
| Fuel benefits | $$ FB\_{t}$$ | *See* Table 12. |
| Water benefits | $$ H2OB\_{t}$$ | *See* Table 12. |

Algorithms

 TRC ratios, net benefits, and levelized costs are detailed in Table 11 below. While some of the inputs are available in Table 10, above, other inputs must be calculated. These input formulae are provided on the next page, in Table 12.

Table 11: Primary Algorithms

|  |  |
| --- | --- |
| $$TRC Ratio\_{gross}$$ | $$=\frac{TRC Benefits\_{gross}}{TRC Costs\_{gross}}$$ |
| $$TRC Ratio\_{net}$$ | $$=\frac{TRC Benefits\_{net}}{TRC Costs\_{net}}$$ |
| $$PV Net Benefits\_{gross}$$ | $$=TRC Benefits\_{gross}-TRC Costs\_{gross}$$ |
| $$PV Net Benefits\_{net}$$ | $$=TRC Benefits\_{net}-TRC Costs\_{net}$$ |
| $$Levelized Cost per kWh\_{gross}$$ | $$=\frac{TRC Costs\_{gross}}{\left[\sum\_{t=1}^{N}\frac{\sum\_{t=1}^{n}EB\_{t}}{\left(1+d\right)^{t-1}}\right]}$$ |
| $$Levelized Cost per kW\_{gross}$$ | $$=\frac{TRC Costs\_{gross}}{\left[\sum\_{t=1}^{N}\frac{\sum\_{t=1}^{n}DB\_{t}}{\left(1+d\right)^{t-1}}\right]}$$ |
| $$Levelized Cost per kWh\_{net}$$ | $$=\frac{TRC Costs\_{net}}{\left[\sum\_{t=1}^{N}\frac{\sum\_{t=1}^{n}EB\_{t}\*NTGR}{\left(1+d\right)^{t-1}}\right]}$$ |
| $$Levelized Cost per kW\_{net}$$ | $$=\frac{TRC Costs\_{net}}{\left[\sum\_{t=1}^{N}\frac{\sum\_{t=1}^{n}DB\_{t}\*NTGR}{\left(1+d\right)^{t-1}}\right]}$$ |

Table 12: Supporting Algorithms

|  |  |
| --- | --- |
| $$NTGR$$ | $$=1-FR+SO+ME$$ |
| $$TRC Benefits\_{gross}$$ | $$=\sum\_{t=1}^{N}\frac{\begin{array}{c} \\EB\_{t}+DB\_{t}+ FB\_{t} + H2OB\_{t}+ O\&M\_{t}\end{array}}{\left(1+d\right)^{t-1}}$$ |
| $$TRC Costs\_{gross}$$ | $$=\sum\_{t=1}^{N}\frac{PA\_{t} + IMC\_{t} - OI\_{t}}{\left(1+d\right)^{t-1}}$$ |
| $$TRC Benefits\_{net}$$ | $$=NTGR\*(TRC Benefits\_{gross})$$ |
| $$TRC Costs\_{net}$$ | $$= \sum\_{t=1}^{N}\frac{PA\_{t} + (IMC\_{t}- OI\_{t})\*(NTGR) }{\left(1+d\right)^{t-1}}$$ |
| $EB\_{t}$ (Electric energy benefits in year *t* summed across *p* costing periods) | $$=E\_{t,p}\*LLF\_{elec}\*(MCE\_{t,p}+AEPS)$$ |
| $ DB\_{t}$ (Capacity benefits in year *t*) | $$= D\_{t}\*LLF\_{elec}\*MCD\_{t}$$ |
| $ FB\_{t}$ (Fuel benefits in year *t*) | $$=\left(F\_{impact}\_{t}- F\_{waste}\_{t} \right)\*LLF\_{gas}\*MCF\_{t}$$ |
| $ H2OB\_{t}$ (Water benefits in year *t*) | $$=H2O\_{t}\*LLF\_{H2O}\*MCH2O\_{t}$$ |

# **Appendix B**

**List of Acronyms and Definitions**

ACC: Avoided Costs Calculator MS-Excel spreadsheet calculation model

AEC: Alternative Energy Credit

AEO: Annual Energy Outlook

AEPS: Alternative Energy Portfolio Standards

AFUE: Annual Fuel Utilization Efficiency

AWWA: American Water Works Association

B/C: Benefit/Cost

BGE: Baltimore Gas and Electric

BRA: Base Residual Auction

BTU: British Thermal Unit

CAGR: Compound Annual Growth Rate

California Manual: 2002 California Standard Practice Manual

CBO: Congressional Budget Office

CHP: Combined Heat and Power

C&I: Commercial and Industrial

CSP: Conservation Service Provider

DLC: Direct Load Control

DR: Demand Response

DRIPE: Demand Reduction Induced Price Effects

DSM: Demand Side Management

EDC: Electric Distribution Company

EE: Energy Efficiency

EE&C: Energy Efficiency and Conservation

EIA: Energy Information Administration

EM&V: Evaluation, Measurement, and Verification

EPA: Environmental Protection Agency

FR: Free-Ridership, Free Rider

GDP: Gross Domestic Product

GTD: Generation, Transmission, and Distribution

Henry Hub: A natural gas pipeline located in Erath, Louisiana. that serves as the official delivery location for NYMEX futures

HSPF: Heating Seasonal Performance Factor

IMC: Incremental Measure Cost

LED: Light Emitting Diode

LMP: Locational Marginal Price

ME: Market Effects

MPS: Market Potential Study

NYMEX: New York Mercantile Exchange

NAICS: North American Industry Classification System

NEI: Non-Energy Impact

NPV: Net Present Value

NSPM: National Standard Practice Manual

NTG: Net-to-Gross

NYMEX: New York Mercantile Exchange

O&M: Operation and Maintenance

Phase I: Act 129 requirements from June 1, 2009, through May 31, 2013

Phase II: Act 129 requirements from June 1, 2013, through May 31, 2016

Phase III: Act 129 requirements from June 1, 2016, through May 31, 2021

Phase IV: Potential Act 129 requirements beginning June 1, 2021

PJM: The regional transmission organization (RTO) covering, *inter alia*, Pennsylvania, New Jersey, and Maryland

PSA: Peak Shaving Adjustment

PUC: Public Utility Commission

PVNB: Present value of net benefits

RGGI: Regional Greenhouse Gas Initiative

ROB: Replace on Burnout

RPS: Renewable Portfolio Standard

RTO: Regional Transmission Organization

SO: Spillover

SWE: Statewide Evaluator

T&D: Transmission and Distribution

TETCO M-3: Texas Eastern Transmission Pipeline - an interstate transmission pipeline system from South Texas to New York City, owned by Enbridge; M3 is a trading hub located in Pennsylvania.

THI: Temperature Humidity Index

TRC: Total Resource Cost

TRM: Technical Reference Manual

TUS: Commission’s Bureau of Technical Utility Services

WACC: Weighted Average Cost of Capital

# **Appendix C**

**Summary of Continuations/Changes/Clarifications/New Items**

|  |  |  |
| --- | --- | --- |
| **Sub-section** | **Subsection Name** | **Summary of Continuation/Change/****Clarification/New Item** |
| **A - General Issues** |
| **1** | TRC Test Assumptions in Other Matters | TRC Test assumptions are used exclusively for Act 129 related matters. TRC Test assumptions are not presumed binding in other regulatory matters such as prudence, cost-of-service, etc. |
| **2** | Frequency of Review of TRC Test | TRC Test applies for entirety of Phase IV.Commission reserves right to update or modify during Phase IV. |
| **3** | Level at Which to Calculate and Report TRC Test Results | Continue cost-effectiveness reporting at portfolio level, not program or measure level. EDCs are required to estimate and report program level TRC ratios in each annual report. |
| **4** | Discount Rate | Change discount rate to 5% nominal (3% in real terms). Previously used an EDC’s WACC. |
| **5** | Effective Useful Life | Continue using statutorily mandated 15-year maximum even if technology exceeds that. Continue to develop dual baselines for technologies where appropriate.Continue no pro-ration of up-front costs and classify as incurred in full during Year 1 of the measure and classify as incurred in full during Year 1 of the measure.Continue adjusting to NPV for on-going costs related to an installed measure when costs are estimated to occur up to and including year 15.Continue to exclude on-going costs beyond a 15-year measure life. |
| **6** | Low-Income Programs | Continue reporting low-income programs as previously done. |
| **7** | Basis of TRC Test Impacts | Continue reporting verified net savings and verified gross savings.Describe how these were calculated.Continue reporting TRC Test ratios on projected gross savings and projected net savings. |
| **8** | Measures Supported by Act 129 Programs and Other Funding Streams | Continue tracking non-Act 129 incentives that are reasonably quantifiable. |
| **B - Avoided Costs of Supplying Electricity** |
| **n/a** |  | Use Avoided Cost Calculator (ACC) to aid in implementation of proposed methodology. |
| **1** | Vintage of Avoided Costs Forecasts | Continue to develop single forecast of avoided costs for use in Phase IV EE&C plans and cost-effectiveness reporting in annual reports. |
| **2** | Avoided Cost of Electric Energy | Change in methodology of calculations. Forecasted avoided energy costs to be calculated in seasonal- and time-differentiated format. Continue to use 20-year period but that period is broken into three segments. Use specific futures markets based on territory served. |
| **3** | Nominal vs. Real Dollars | Continue to develop avoided costs forecasts in nominal dollars.Use nominal discount rate to calculate NPV. |
| **4** | Line Losses | Use line loss assumptions by EDC and class as listed in the 2021 TRM. |
| **5** | Escalation Rate | Use 2% inflation as the escalation per year. |
| **6** | Avoided Cost of Generation Capacity | Change in methodology of calculation. |
| **7** | Avoided Cost of Transmission and Distribution Capacity | Fundamental calculation to stay consistent, but order of operations is changed. Clarify avoided costs in distribution should not be applied to EE measures for Large C&I customers taking service at primary voltage. |
| **8** | Compliance with AEPS | AEPS costs set at $0.843 per MWh for first year of Phase IV and escalate yearly at 2% inflation. |
| **9** | Price Suppression Effects | Continue to exclude effects of price suppression in 2021 TRC Test calculations. |
| **10** | End Use Adjustments | Continue use of end-use profiles, when available. |
| **C - Other TRC Benefits** |
| **1** | Quantifying Water Impacts | Methodology to quantify water decreases/increases based on March 25, 2018 guidance memo in Phase III and include TRC benefits from water savings for those measures where either the 2021 TRM provides all necessary inputs and assumptions to calculate them or this Order presents default savings levels. |
| **2** | Monetizing Water Impacts | Methodology to monetize water decreases/increases based on March 25, 2018 guidance memo in Phase III and use $0.01 per gallon (in 2021 dollars) as the marginal cost of water escalated annually over the forecast horizon, with a loss factor of 24.5% (1.32 multiplier) to be applied to all savings calculated at the end use level. |
| **3** | Quantifying Fossil Fuel Impacts | Methodology to quantify fossil fuel decreases/increases based on March 25, 2018 guidance memo in Phase III with further provisions for residential new construction, air sealing and insulation, and ENERGY STAR windows and thermostats. Use 80% recovery efficiency for gas units. |
| **4** | Interactive Effects | EDCs may choose between two methods to estimate interactive effects of non-residential lighting. |
| **5** | Monetizing Fossil Fuel Impacts | Use natural gas (NG) values in Section B.2 (Avoided Cost of Electric Energy), collapsed into a single value. Continue to use 20-year period but propose that period is broken into three segments. Use NG loss factor of 4.167%. |
| **6** | O & M Benefits | Continue to include avoided replacement costs and labor in TRC benefits. Clarify that O&M benefits can be positive or negative. |
| **7** | Societal Benefits | Continue to exclude societal benefits from TRC. |
| **D - TRC Costs** |
| **1** | Program Administration and Overhead | Treat kits and directly installed equipment costs as both incremental measure cost (to the EDC) *and* incentive (to the customer). |
| **2** | Incremental Costs | Continue to use SWE-developed incremental cost database as an optional resource for EDCs and evaluation contractors when actual project costs are not available or appropriate. |
| **3** | Act 129 Incentives | Treat kits and directly installed equipment costs as an incentive to the customer. |
| **4** | Incentives from Outside of Act 129 | Treat incentives from outside Act 129 as reduction in costs, not as benefit to program. |
| **E - Fuel Switching** |
| **1** | ENERGY STAR Requirement | State proposed minimum performance standard and provide justification for fuel switching measures that have no ENERGY STAR performance standard in EE&C plans. |
| **2** | Increased Fuel Consumption | Treat increased fuel consumption as a negative TRC benefit. |
| **F - Net-to-Gross (NTG) Issues** |
| **1** | Use of NTG Research | Continue NTG research, use results for program planning purposes, and report 2021 TRC Test ratios based on projected gross savings and net savings. |
| **2** | Treatment of Incentives to Free-Riders | Continue excluding free-rider incentives as increased cost when considering net TRC perspective. |
| **3** | Treatment of NTG for TRC Benefits | Clarify that NTG ratios shall be applied to *all* benefits in 2021 TRC Test. |
| **G - Demand Response (DR)** |
| **1** | Testing if DR is Included in Phase IV | DR has not yet been determined, but guidance to calculate TRC benefits and costs for DR is included. |
| **2** | Calculation of DR Benefits | Use average gross verified demand reductions over each hour of performance and apply line loss adjustment factor. Use EDC-specific fraction of avoided cost of generation capacity based on PJM analysis and 60% of avoided T&D costs for program year to monetize DR impacts. |
| **3** | Participant Cost Assumption | Continue to use 75% participant cost assumption. |
| **4** | Measure Life | Measure life for direct load control DR equipment to be equivalent to the length of Phase IV. Clarify that DR equipment purchased in prior phase should not be counted in Phase IV. |
| **H. Additional Matters** |
| **1** | Applicability of NSPM to the Act 129 TRC Test | No action taken to apply NSPM to the 2021 TRC Test Order. Will consider in preparation of future TRC Test Orders. |
| **2** | Creation of an Energy Efficiency Technical Advisory Committee | No Energy Efficiency Technical Advisory Committee will be formed at this time. |
| **3** | Demand Response Requirements by Utility | “Cap and trade” system for DR requirements will be taken under advisement when reviewing the Phase III SWE’s Phase IV DR MPS. |
| **4** | Formula Error in Appendix A | Corrected error in Appendix A. |

1. The currently assigned docket for matters relating to the Commission’s consideration of a potential Phase IV is *Release of the Act 129 [Phase III SWE] Energy Efficiency Baseline Studies*, Docket No. M‑2019-3006866. The 2021 Technical Reference Manual (TRM) is at Docket No. M­2019-3006867. [↑](#footnote-ref-2)
2. After 2013, the Commission has had the option to determine what test to use. 66 Pa. C.S. § 2806.1(m). [↑](#footnote-ref-3)
3. Section 2806.1(c)(3) states that, based on a review to be concluded by November 30, 2013, if “the Commission determines that the benefits of the program exceed the costs, the Commission shall adopt additional incremental reductions in consumption.” [↑](#footnote-ref-4)
4. The SWE is a team of technical consultants. They are engaged by the Commission under contract pursuant to a request for proposal (RFP) process. The SWE for Phase I consisted of GDS Associates, Inc. and its subcontractors. [↑](#footnote-ref-5)
5. Act 129 sets a limit on the cost of an EDC’s EE&C plan at 2% of the EDC’s annual revenue as of December 31, 2006. *See* 66 Pa. C.S. § 2806.1(g). [↑](#footnote-ref-6)
6. *See* <http://www.puc.pa.gov/electric/pdf/Act129/Act129-PA_Market_Potential_Study051012.pdf>. The *EE Potential Study* is dated May 10, 2012 and was released May 11, 2012. [↑](#footnote-ref-7)
7. Demand Response is a change in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. Usually, incentive payments are offered to customers to induce lower electric consumption at times of high wholesale market prices or when system reliability is jeopardized. Examples include turning up the temperature on the thermostat to reduce air conditioning or slowing down/stopping production at an industrial facility temporarily. [↑](#footnote-ref-8)
8. *See* GDS Associates, Inc. (Phase I SWE), Act 129 Demand Response Study (dated May 13, 2013). <http://www.puc.pa.gov/pcdocs/1256728.docx>. [↑](#footnote-ref-9)
9. The SWE for Phase II consisted of GDS Associates, Inc., and its subcontractors. [↑](#footnote-ref-10)
10. The *DR Potential Study*, dated February 25, 2015, was released February 27, 2015. *See* <http://www.puc.pa.gov/pcdocs/1345077.docx>. [↑](#footnote-ref-11)
11. *See* <http://www.puc.state.pa.us/pcdocs/1367313.doc>. [↑](#footnote-ref-12)
12. *See* <http://www.puc.pa.gov/pcdocs/1367195.docx>. [↑](#footnote-ref-13)
13. *The California Standard Practice Manual – Economic Analysis of Demand‑Side Programs and Projects*, July 2002, p. 18. *See* <http://www.calmac.org/events/SPM_9_20_02.pdf>. [↑](#footnote-ref-14)
14. In this regard, we note that the 2021 TRC Test would continue to use the incremental measure costs of services and equipment. This matter is discussed in more detail below, in the segment addressing incentive payments from an EDC. [↑](#footnote-ref-15)
15. *See* Appendix A – TRC Definitions and Formulae of this Final Order for detailed methodology to calculate the PVNB and B/C ratio of the 2021 TRC Test. [↑](#footnote-ref-16)
16. After November 30, 2013, and every five years thereafter, the Commission is to evaluate the costs and benefits of the EE&C program established under Section 2806.1(a) and of the approved EE&C plans using a TRC test or a benefit/cost analysis of the Commission’s determination. 66 Pa. C.S. § 2806.1(c)(3). [↑](#footnote-ref-17)
17. The SWE for Phase III is NMR Group, Inc. and its subcontractors. The SWE for Phase IV has not been determined at the time of this Final Order. [↑](#footnote-ref-18)
18. *See* <https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf>. [↑](#footnote-ref-19)
19. AEME late-filed its comments on November 6. 2019. [↑](#footnote-ref-20)
20. The Industrials filed a petition to late-file comments, with a copy of the comments attached, on November 6, 2019. [↑](#footnote-ref-21)
21. In initial comments, BPA filed with other entities as part of the Joint Intervenors. In reply comments, BPA filed comments alone. No other entities that were part of the Joint Intervenors filed additional reply comments. [↑](#footnote-ref-22)
22. The mailbox rules in 52 Pa. Code § 1.11(a)(2)-(4) did not apply. [↑](#footnote-ref-23)
23. *See* <http://www.puc.pa.gov/utility_industry/natural_gas/voluntary_natgas_eecp.aspx> [↑](#footnote-ref-24)
24. *See* <https://www.cbo.gov/system/files/2019-03/54918-Outlook-3.pdf> at pages 21-24. [↑](#footnote-ref-25)
25. *See* <http://www.puc.pa.gov/pcdocs/1057172.docx>. [↑](#footnote-ref-26)
26. *See* <http://www.puc.state.pa.us/pcdocs/1190750.docx> at page 4. [↑](#footnote-ref-27)
27. *See* <http://www.puc.pa.gov/pcdocs/1367195.docx> at page 66. [↑](#footnote-ref-28)
28. *See* <https://tradingeconomics.com/united-states/gdp-growth>. [↑](#footnote-ref-29)
29. *See* <https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf>. [↑](#footnote-ref-30)
30. *See* <https://aceee.org/files/proceedings/2014/data/papers/8-1084.pdf>. [↑](#footnote-ref-31)
31. *See* <https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf> page 91. [↑](#footnote-ref-32)
32. Industrials Reply Comments at 9. [↑](#footnote-ref-33)
33. California Standard Practice Manual at 19. [↑](#footnote-ref-34)
34. The following definitions are from Table 1-3 of the 2021 TRM: The three seasonal periods are Summer (May-September), Winter (December-February), and Shoulder (March-April and October-November). The two time periods in each seasonal period are “on-peak,” defined as 7am to 11pm on weekdays, and “off-peak,” defined as 11pm to 7am on weekdays and all weekend and holiday hours. [↑](#footnote-ref-35)
35. NYMEX is the New York Mercantile Stock Exchange; it is owned and operated by CME Group of Chicago. *See* [https://www.cmegroup.com/company/nymex.html](https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.cmegroup.com%2Fcompany%2Fnymex.html&data=02%7C01%7Cdedinger%40pa.gov%7Cdbbc9d02bd87440dff9e08d7200c01fd%7C418e284101284dd59b6c47fc5a9a1bde%7C0%7C1%7C637013108269708403&sdata=ZK7kWQBxGerewc13t2llcp5KQ3OYcbVyPutTTN%2FsdKU%3D&reserved=0). [↑](#footnote-ref-36)
36. <https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019.shtml> [↑](#footnote-ref-37)
37. For instance, if the EDC EE&C plan is due in November 2020, the prompt month will be August 2020. [↑](#footnote-ref-38)
38. “Spark price spread” (or simply “Spark spread”) is a common metric for estimating the profitability of natural gas-fired electric generators. The spark spread is the difference between the price received by a generator for electricity produced and the cost of the natural gas needed to produce that electricity. *See* EIA definition at<https://www.eia.gov/todayinenergy/includes/sparkspread_explain.php>. [↑](#footnote-ref-39)
39. Henry Hub is a distribution hub in Erath, LA, on a natural gas pipeline, that serves as the official delivery location for NYMEX futures. *See* [https://www.naturalgasintel.com/data/data\_products/daily?location\_id=SLAHH&region\_id=south-louisiana](https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.naturalgasintel.com%2Fdata%2Fdata_products%2Fdaily%3Flocation_id%3DSLAHH%26region_id%3Dsouth-louisiana&data=02%7C01%7Cdedinger%40pa.gov%7Cdbbc9d02bd87440dff9e08d7200c01fd%7C418e284101284dd59b6c47fc5a9a1bde%7C0%7C1%7C637013108269718398&sdata=n1KfCYDA14NuEuQPi42Twl2t0eHh%2BFI6XEqCiBfIB9o%3D&reserved=0). [↑](#footnote-ref-40)
40. TETCO is the Texas Eastern Transmission Pipeline, an interstate transmission pipeline system extending from South Texas to New York City, owned by Enbridge. M3 is a trading hub located in Pennsylvania. *See* [https://www.ferc.gov/market-oversight/mkt-gas/northeast/2009/10-2009-ngas-ne-archive.pdf](https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.ferc.gov%2Fmarket-oversight%2Fmkt-gas%2Fnortheast%2F2009%2F10-2009-ngas-ne-archive.pdf&data=02%7C01%7Cdedinger%40pa.gov%7Cdbbc9d02bd87440dff9e08d7200c01fd%7C418e284101284dd59b6c47fc5a9a1bde%7C0%7C1%7C637013108269718398&sdata=RahnIakgNoYf895Ti%2BqV59BSKJ0yTtztoxMtIDDSvcA%3D&reserved=0). [↑](#footnote-ref-41)
41. Transco is the Interstate transmission pipeline system extending from South Texas to New York City, owned by Williams. Zone 6 Non-NY is a trading hub located in Pennsylvania. *See* [https://www.ferc.gov/market-oversight/mkt-gas/northeast/2009/10-2009-ngas-ne-archive.pdf](https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.ferc.gov%2Fmarket-oversight%2Fmkt-gas%2Fnortheast%2F2009%2F10-2009-ngas-ne-archive.pdf&data=02%7C01%7Cdedinger%40pa.gov%7Cdbbc9d02bd87440dff9e08d7200c01fd%7C418e284101284dd59b6c47fc5a9a1bde%7C0%7C1%7C637013108269728396&sdata=KivsD7dVHzJ4cSAIERwWpL8402Xs36mdS0bCZNncIQk%3D&reserved=0). [↑](#footnote-ref-42)
42. EIA Annual Report table 8.2 is the source for the average existing natural gas prime mover in the United States. *See* <https://www.eia.gov/electricity/annual/html/epa_08_02.html>. [↑](#footnote-ref-43)
43. *See* <http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/technical_reference_manual.aspx>. [↑](#footnote-ref-44)
44. *See* <https://data.bls.gov/timeseries/PCU221110221110>. [↑](#footnote-ref-45)
45. A Program Year (PY) is the year in which Act 129 reporting requirements must be fulfilled and provides the timeframe for Act 129 compliance. All program years begin on June 1 and end on May 31 of the following year. The years run sequentially starting with Phase I. For example, PY13 would begin June 1, 2021, and end May 31, 2022. [↑](#footnote-ref-46)
46. *See* <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-results.ashx?la=en> [↑](#footnote-ref-47)
47. The Phase IV calculation would differ from the Phase III calculation in that Phase III required calculation of annual expenditure divided by growth forecast and then the annual results were averaged. The proposal for Phase IV is that the expenditures will be summed and divided by the sum of growth forecasts and then divided by the number of years. *See Act 129 Statewide Evaluator Demand Response Potential for Pennsylvania – Final Report*,Docket No. M-2014-2424864 at page 38 (February 27, 2015). *See* <http://www.puc.pa.gov/pcdocs/1345077.docx>. [↑](#footnote-ref-48)
48. Table 1 was calculated by the Phase III SWE based on capital expenditures provided by the EDCs as well as PJM’s zonal peak load forecasts at [https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx](https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.pjm.com%2F-%2Fmedia%2Flibrary%2Freports-notices%2Fload-forecast%2F2019-load-report.ashx&data=02%7C01%7Cdedinger%40pa.gov%7C497acd651ce747a661a308d720ac1234%7C418e284101284dd59b6c47fc5a9a1bde%7C0%7C1%7C637013795730139375&sdata=paZlquFDMjQvhP1Do7VKkR0eaMcCZvRf5qeV%2FnzkgBA%3D&reserved=0). [↑](#footnote-ref-49)
49. Table 2 was also calculated by the Phase III SWE based on capital expenditures provided by the EDCs as well as PJM’s zonal peak load forecasts at [https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx](https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.pjm.com%2F-%2Fmedia%2Flibrary%2Freports-notices%2Fload-forecast%2F2019-load-report.ashx&data=02%7C01%7Cdedinger%40pa.gov%7C497acd651ce747a661a308d720ac1234%7C418e284101284dd59b6c47fc5a9a1bde%7C0%7C1%7C637013795730139375&sdata=paZlquFDMjQvhP1Do7VKkR0eaMcCZvRf5qeV%2FnzkgBA%3D&reserved=0). [↑](#footnote-ref-50)
50. *See* 73 P.S. §§ 1648.1–1648.8 and 66 Pa. C.S. § 2814. *See also* 52 Pa. Code §§ 75.1–75.72. [↑](#footnote-ref-51)
51. *See* AEPS Act Historical Pricing reports at <https://www.pennaeps.com/reports/>. [↑](#footnote-ref-52)
52. *See* 71 P.S. § 714*.* [↑](#footnote-ref-53)
53. Marex Spectron is a United Kingdom-based broker of financial instruments and provider of market data services across the metals, agricultural and energy markets. *See* <https://www.marexspectron.com/about-us>. [↑](#footnote-ref-54)
54. The AEPS Act avoided cost is established using a price of $55 for solar photovoltaic sources at 0.5% of retail sales; $6.30 for Tier I sources at 8% of retail sales; and $0.53 for Tier II sources at 10% of retail sales. Obligations are set in <https://www.pabulletin.com/secure/data/vol38/38-51/2286.html>. [↑](#footnote-ref-55)
55. For a detailed explanation of the economics and benefits of DRIPE, *see* Industrial Energy Efficiency & Combined Heat and Power Working Groups, *State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All*, (December 2015), <https://www4.eere.energy.gov/seeaction/system/files/documents/DRIPE-finalv3_0.pdf>, at page 5. [↑](#footnote-ref-56)
56. *See Release of the Act 129 Demand Response Study – Final Report and Stakeholders’ Meeting Announcement*, at <http://www.puc.pa.gov/pcdocs/1230512.docx>. [↑](#footnote-ref-57)
57. The May 2013 and November 2013 versions of the *SWE’s Act 129 Demand Response Study – Final Report* are available on the Commission’s website at <http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/act_129_statewide_evaluator_swe_.aspx>. [↑](#footnote-ref-58)
58. *See Energy Efficiency and Conservation Program* Tentative Order, Docket Nos. M-2012-2289411 and M-2008-2069887 (entered November 14, 2013). [↑](#footnote-ref-59)
59. *See Energy Efficiency and Conservation Program* Final Order, Docket Nos. M-2012-2289411 and M‑2008-2069887 (entered Feb. 20, 2014) (PDR Cost Effectiveness Determination Final Order). [↑](#footnote-ref-60)
60. Generally speaking, supply resources are increases in supply, and demand resources reduce demand for electricity from the power system. [↑](#footnote-ref-61)
61. Final Order on the TRC Test for Phase III of Act 129, Docket No. M-2015-2468992 (order entered June 22, 2015) at page 14. [↑](#footnote-ref-62)
62. *See* <http://www.waterrf.org/PublicReportLibrary/RFR90781_1999_241A.pdf> at pages 95-96, 100. [↑](#footnote-ref-63)
63. *See* <http://www.waterrf.org/PublicReportLibrary/4309A.pdf> at page 9. [↑](#footnote-ref-64)
64. Phase III SWE calculations using 2021 TRM assumptions. Note that water savings applies to the clothes washer only. [↑](#footnote-ref-65)
65. *See* NMR Group, Inc. (Phase III SWE), *2018 Pennsylvania Statewide Act 129 Residential Baseline Study*, at 170, at Docket No. M-2019-3006866 (released on February 14, 2019). *See* <http://www.puc.pa.gov/Electric/pdf/Act129/SWE-Phase3_Res_Baseline_Study_Rpt021219.pdf> [↑](#footnote-ref-66)
66. *See* GDS Associates, Inc. (Phase II SWE), *2014 Pennsylvania Statewide Act 129 Residential Baseline Study*, at 105, at Docket No. M-2014-2424864 (released on June 12, 2014). *See* <http://www.puc.pa.gov/Electric/pdf/Act129/SWE-2014_PA_Statewide_Act129_Residential_Baseline_Study.pdf>. [↑](#footnote-ref-67)
67. *See 2018 Pennsylvania Statewide Act 129 Non-Residential Baseline Study,* at Docket No. M-2019-3006866 (released on February 14, 2019). *See*<http://www.puc.pa.gov/Electric/pdf/Act129/SWE-Phase3_NonRes_Baseline_Study_Rpt021219.pdf>. [↑](#footnote-ref-68)
68. *See 2018 Pennsylvania Statewide Act 129 Non-Residential Baseline Study,* at Docket No. M-2019-3006866 (released on February 14, 2019). *See*<http://www.puc.pa.gov/Electric/pdf/Act129/SWE-Phase3_NonRes_Baseline_Study_Rpt021219.pdf>. [↑](#footnote-ref-69)
69. *See* <https://www.oa.pa.gov/Policies/eo/Documents/2019-07.pdf>. [↑](#footnote-ref-70)
70. *See* <http://www.puc.state.pa.us/Electric/pdf/Act129/SWE_PhaseIII-Evaluation_Framework050818.pdf> at page 83. [↑](#footnote-ref-71)
71. *2007 Clarification Memo* at 154-158 regarding the *2002 CSPM*, from D.07-09-043; *see* <http://www.cpuc.ca.gov/NR/rdonlyres/A7C97EB0-48FA-4F05-9F3D-4934512FEDEA/0/2007SPMClarificationMemo.doc>. [↑](#footnote-ref-72)
72. *See* <http://www.puc.state.pa.us/Electric/pdf/Act129/Act129-SWE_AR_Y9_022819.pdf>, page 14. [↑](#footnote-ref-73)
73. For a more thorough explanation of PRD and how it functions, see PJM’s Price Responsive Demand Fact Sheet at <https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/price-responsive-demand.ashx>. [↑](#footnote-ref-74)
74. *See* PJM Load Forecast Report (January 2019) at 43 and 66, <https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en>. [↑](#footnote-ref-75)
75. *See* PJM Load Forecast Report (March 2019) at 41 and 65, <https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-rpm-load-forecast.ashx?la=en>. [↑](#footnote-ref-76)
76. The non-coincident peak load forecast is zonal, capturing only a specific EDC. [↑](#footnote-ref-77)
77. The coincident peak demand forecast reflects the relationship of a zone to the PJM footprint. [↑](#footnote-ref-78)
78. Characteristics of Pennsylvania EDCs supplied by the Commission and Phase III SWE and given to PJM’s load forecasting group to model the coincident and non-coincident summer peak demand forecast impacts of a hypothetical Phase IV DR program. [↑](#footnote-ref-79)
79. Phase III SWE calculations using the results of zonal peak demand forecasts completed by PJM with and without PSA*.* [↑](#footnote-ref-80)
80. *See* [http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm](http://www.cpuc.ca.gov/PUC/energy/Demand%2BResponse/Cost-Effectiveness.htm). [↑](#footnote-ref-81)
81. *See* [http://www.puc.pa.gov/filing\_resources/issues\_laws\_regulations/act\_129\_information/total\_resource cost test.aspx](http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/total_resource%20cost%20test.aspx). [↑](#footnote-ref-82)