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

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

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| Gladys Brown Dutrieuille, Chairman |  |
| David W. Sweet, Vice ChairmanNorman J. Kennard |  |
| Andrew G. Place |  |
| John F. Coleman, Jr. |  |
|  |  |
| 2021 Total Resource Cost (TRC) Test | M-2019-3006868 |

**Tentative 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. Before us is the proposed guidance for implementing the Pennsylvania Total Resource Cost (TRC) Test for use in planning for and during a potential Phase IV of Act 129, that, if approved, would begin June 1, 2021.[[1]](#footnote-2) As ultimately approved, this version of the TRC Test for use in the potential Phase IV will be designated the 2021 TRC Test.

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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 (Phase I). 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. In particular, Act 129 required an 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 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 energy efficiency 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 Order* at Docket No. M‑2015-2468992 on June 22, 2015.[[12]](#footnote-13) Phase III 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 the potential Phase IV, the Commission has chosen to put forth this Tentative 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 Project*[[13]](#footnote-14)(*California Manual*),for the B/C analysis of EE&C plans for the 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 *(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 Tentative TRC Test Order for Phase IV, we shall attempt to provide all instructions in a comprehensive document. 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 are proposing changes. Comments are to follow the outline numbering established herein. If parties have comments on a provision not in the outline, address them after making comments relative to items in the outline.

**2021 Technical Reference Manual (TRM) and Phase IV 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.

A final order at this docket regarding the 2021 TRC Test will set forth constraints that the Phase III SWE will need in order to finalize the Phase IV market potential study.

# 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 a given 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 proposes a change to the discount rate for Phase IV, as discussed in Section A.4 Discount Rate, below.

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 Tentative Order, the Commission and the SWE[[17]](#footnote-18) have 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 TRC Test for Phase IV, if implemented, would be applicable throughout the course of Phase IV, 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.

This Tentative Order sets out the proposed continuations and clarifications from the prior TRC Tests and the proposed changes for the 2021 TRC Test for use in a potential Phase IV. The continuations, clarifications, changes, and new items are summarized in Appendix C and explained in detail in this Tentative Order.

## 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 proposes 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.

### Frequency of Review of the TRC Test

Consistent with our determination in the 2016 TRC Test Order, the Commission proposes to maintain the provision that the 2021 TRC Test apply for the entirety of Phase IV. This will 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 Tentative TRC Test Order 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 reserve the right to update or modify the 2021 TRC Test Order during Phase IV or to direct the SWE to develop guidance memos on such topics to promote consistency across EDCs and TRC Test results that are in line with the policy objectives of the Commonwealth.

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

For Phase IV, the Commission proposes to determine cost-effectiveness separately for EE and DR at the EE&C plan level. This proposal is consistent with guidance in the 2016 TRC Test Order, which stated “compliance will be measured separately going forward in any phase for which there will be DR or EE goals*.*” *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 are able to contribute to the EE and DR goals of Act 129.

As in prior phases, the Commission proposes to continue applying the TRC Test at the plan level and will 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).

### 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 this Act 129 is an energy efficiency and conservation program, we are proposing to use the discount rate that reflects the preferences of the public at large.

Therefore, the Commission now proposes 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 propose 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.[[19]](#footnote-20) Proposing these percentages is a change from prior TRC Tests.

Act 129 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[[20]](#footnote-21), 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[[21]](#footnote-22) simply stated that the “discount rate for the [2013] Pennsylvania TRC Test is the EDC’s weighted average cost of capital,” while the 2016 TRC Test Order[[22]](#footnote-23) 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.[[23]](#footnote-24) 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,[[24]](#footnote-25) as is the case here. Finally, this additional research also determined that a 3% real discount rate is consistent with the discount rates that have been used for energy efficiency programs in other jurisdictions.[[25]](#footnote-26)

### 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”[[26]](#footnote-27) 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 serve to circumvent the legislative directive. Therefore, we see 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. For the 2021 TRC Test, EDCs and their evaluation contractors are to continue to use dual baselines where appropriate and practical. For example, if a change in standards were expected to take effect in 2020, the change would overlap with the last year of Phase III, 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.

### Low-Income Programs

The Commission is not proposing 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.

### Basis of TRC Test Impacts

The Commission proposes no changes and would continue the process established in Phase III, under which 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. Compliance will be based on “verified gross” kWh and kW electric savings, and costs will be based on “actual” costs. Because EDCs use net savings for planning purposes, they shall also continue to report net savings for each program and the total portfolio of programs and describe how such net savings are calculated. In addition, EDCs shall 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 will also be projected.

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

The Commission is not proposing 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 recognizes 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 proposes 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 can 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.

## Avoided Costs of Supplying Electricity

The Commission proposes continued use of the *status quo* Act 129 methodology to develop forecasted avoided costs of electricity but proposes slight modifications. The intention is that more detailed instructions will improve consistency across EDCs and lead to better alignment with market conditions. To meet this objective, the Phase III SWE has developed a new MS-Excel spreadsheet calculation model (Avoided Costs Calculator or ACC) to implement the methodology outlined in this Tentative Order. We are proposing that EDCs must use this standard tool when developing avoided costs for Phase IV. The Avoided Costs Calculator 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 are 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

EDCs will 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 will not be expected to update avoided costs mid-phase. The Commission reserves the right to require updating, and the EDCs may request updating depending on market changes.

### Avoided Cost of Electric Energy

The methodology will continue to use a 20-year period. The proposed modification in methodology entails the calculations for avoided electricity energy costs; the period is dissected into three segments, as discussed below. This Tentative Order proposes that forecasted avoided energy costs continue to be calculated in a time-differentiated format but proposes to change from four to six distinct periods per annum, as defined in the 2021 TRM at Table 1-3,[[27]](#footnote-28) 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[[28]](#footnote-29) PJM electricity futures prices for on-peak and off-peak periods as a basis. The Commission is proposing 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*. The zonal adjustment factor will 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 will 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, the Commission proposes to disallow this for Phase IV due to inconsistent and incomplete futures price data at the zonal level. In addition, we propose that the prompt month for NYMEX PJM electricity futures be established as three months prior to the EE&C plan filing date.[[29]](#footnote-30)

#### The second segment – years five through ten: The proposed methodology for segment two (calendar years 2026 through 2031) will be based on NYMEX natural gas futures converted into electricity costs. Medium-term NYMEX natural gas futures will 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 is that natural gas costs shall be converted into an electric energy price with an additional spark price spread,[[30]](#footnote-31) using the following calculation steps:

* + 1. Collect monthly NYMEX natural gas futures at Henry Hub[[31]](#footnote-32) 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[[32]](#footnote-33) 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[[33]](#footnote-34) as the destination. For EDCs that have service territory on both sides of the river, such as PPL Utilities and Metropolitan Edison, the location shall be based where the majority of the electric load is present. EDC locational adjustments for the NYMEX reference natural gas price shall 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 shall 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 together NYMEX natural gas futures and the AEO projected natural costs over the segment two period. The Commission proposes that this shall 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 shall be used for on-peak periods and the heat rate of a combined cycle unit shall be used for off-peak periods. The proposed heat rate for on-peak shall be 7,649 BTU/kWh, and off-peak shall be 11,176 BTU/kWh.[[34]](#footnote-35)
		6. Add a spark spread cost to the avoided energy costs for segment 2. The spark spread shall 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 methodology for segment three (calendar year 2032 through 2041) shall be a similar methodology as for the second segment, but the Commission proposes that it be based solely on long-term AEO projected natural gas costs. Under the proposed modification, natural gas projected costs shall be converted into an electric energy price through the use of 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 shall 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 shall be the same as determined in the second segment.

### Nominal vs. Real Dollars

The Commission proposes that for Phase IV, EDC avoided cost forecasts will 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.

### Line Losses

The algorithms and assumptions in the 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[[35]](#footnote-36) provides line loss factors by EDC and customer class. The Commission proposes that EDCs continue to use these values to calculate system-level electric energy and peak demand impacts and to determine TRC benefits.

### Escalation Rate

The Commission proposes that any avoided electricity costs that require escalation from a given year shall use the Bureau of Labor Statistics’ (BLS) Electric Power Generation Transmission Distribution (GTD) sector price index[[36]](#footnote-37) (BLS factor: NAICS 221110) as a proxy rate. The escalation statistic shall 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. The escalation rate plus the inflation rate captures the increase in cost projections in nominal dollars.

### Avoided Cost of Generation Capacity

Generation capacity for the region is procured through PJM’s forward capacity auction process – the Reliability Pricing Model. The Base Residual Auctions (BRAs) happen 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 proposes the following methodology:

1. Take a simple average of the three most recent BRA clearing prices for the zone. The Commission’s position is 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).[[37]](#footnote-38)
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.

### Avoided Cost of Transmission and Distribution Capacity

 The Commission proposes continued use of the status quo Act 129 methodology with slight modifications for the calculation of avoided T&D capacity costs. The Phase III SWE requested that EDCs provide capital expenditure data from the EDCs, and the EDCs provided the requested information. The Phase III SWE then produced input assumptions for the Phase IV market potential 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 is 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 is proposed to stay consistent, but the order of operations would be modified from the Phase III calculations.[[38]](#footnote-39) This system-wide perspective is a simplification of the underlying characteristics of EDC systems, which have areas of load growth and areas of declining load. 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 Phase IV values are generally higher than Phase III values, largely because of the limited amount of growth in the Pennsylvania zonal peak load forecasts.

We also 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 do not propose to conduct additional research on this topic in preparation for Phase IV at this time.

The Commission proposes 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 propose 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)[[39]](#footnote-40)

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 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)[[40]](#footnote-41)

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| 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 Commercial and Industrial (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, however, 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 proposes 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 are presuming 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.

### 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[[41]](#footnote-42) 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.[[42]](#footnote-43) 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.[[43]](#footnote-44) To ensure uniform valuation of AECs (and hence avoided cost estimates) by EDCs in their EE&C plans, the Commission proposes to provide EDCs with AEC pricing to use in Phase IV planning.

 The Commission has access to several subscription-based services that forecast AEC pricing, including Marex Spectron.[[44]](#footnote-45) Using forecast data for the year 2021, the Commission proposes that the AEPS Act avoided costs shall be $0.84 per MWh for the first year of Phase IV and escalated by the BLS escalation factor every year thereafter.[[45]](#footnote-46) We are proposing 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. By calculating and providing this value, EDCs will be able to actually include it. Thus, the directive to include AEPS Act avoided costs now includes guidance on the calculation method.

### 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).[[46]](#footnote-47) The Commission has 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.[[47]](#footnote-48) 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*[[48]](#footnote-49) was released for comment on November 14, 2013.[[49]](#footnote-50) 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.[[50]](#footnote-51) 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 are included in the 2016 TRC Test Order for energy efficiency or DR.

For Phase IV, the Commission proposes 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[[51]](#footnote-52) in competitive markets.

### End-Use Adjustments

The Commission proposes continued 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 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 TRC cost while conserved fuel and water were not accounted for as savings in the TRC Test.[[52]](#footnote-53) During PY9, the Phase III SWE issued a guidance memo to the EDCs and their evaluation contractors with instructions on how to treat fossil fuel and water impacts for the remainder of Phase III. The Commission’s proposed treatment of fossil fuel and water impacts for Phase IV builds on this work.

The 2016 TRC Final Order and the Phase III Implementation Order required the inclusion of “reasonably quantifiable” fossil fuel and water benefits in the TRC Test. The Commission maintains this previous position but proposes 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 proposes 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) and Section 3.4.2 of the 2021 TRM (low-flow pre-rinse sprayers) 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. We propose 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. The Phase III SWE and TUS assert that a value of 1,039 gallons/year is a reasonable annual savings assumption for low-flow faucet aerators, based on an average 8.1 minutes/day of faucet use. The Commission, therefore, proposes 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).[[53]](#footnote-54) 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.[[54]](#footnote-55)

ENERGY STAR clothes washers save water and energy, but the 2021 TRM does not provide enough information to calculate the water savings values. Based upon a guidance memo issued in PY10 that reflected the changes in clothes washer standards, the Commission proposes 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[[55]](#footnote-56)

|  |  |  |  |
| --- | --- | --- | --- |
| 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 |

### Monetizing Water Impacts

The Commission proposes that resources be monetized using a marginal cost to reflect what is reduced (or increased) by an EE&C measure. Marginal costs are the appropriate perspective for the TRC Test because other fixed costs embedded in retail rates will still be recovered. We propose that EDCs use $0.01 per gallon ($2021) as the marginal cost of water used for TRC testing. Under the proposal, this rate must be escalated yearly with the same escalation 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 proposes that saved pumping energy from water measures not be counted toward EDC compliance targets.

The 2021 TRM does not include loss rates for water. However, water systems also experience losses in their distribution networks. The Commission proposes 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.

### Quantifying Fossil Fuel Impacts

EDCs will continue to include fossil fuel benefits. 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 now proposes 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 propose 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 proposes the use of 80% recovery efficiency for gas units to monetize any non-electric resource savings.

### 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 Commission, however, proposes a standardization of reporting the heating penalties as a negative benefit in the 2021 TRC Test for efficient lighting. We also propose 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,[[56]](#footnote-57) 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.[[57]](#footnote-58)

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 proposes 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[[58]](#footnote-59) or program records to come up with 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.

### Monetizing Fossil Fuel Impacts

The Commission proposes 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 will 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 Tentative TRC Test Order. We propose 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 entails the use of a 20-year period for calculating avoided electricity energy costs and is 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 shall 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 shall 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 shall 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 proposes that this shall 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. The Commission proposes EDCs use a natural gas loss factor of 4% (1.04167) based on the SWE’s calculations from data provided by the Pipeline and Hazardous Materials Safety Administration.

### 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.

### Societal Benefits

The Commission proposes that, consistent with prior TRC Test Orders, the TRC Test will 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.

## TRC Costs

### Program Administration and Overhead

All program administration and overhead costs 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. 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 will 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, will 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 the 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 propose 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.

### 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 5, below, is adapted from the Pennsylvania Evaluation Framework[[59]](#footnote-60) 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 5: 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. The Commission proposes to have the Phase IV SWE update the Incremental Cost Database by July 1, 2020.

The Commission proposes 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).

### 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 proposes 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.

### 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. The Commission proposes 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 proposes 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 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. If stakeholders run existing values through the new formulae and notice a material difference in the outcome, they may include that information in their comments.

The Commission interprets “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.

## 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 see 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 proposes 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 is a change from the 2016 TRC Test Order.

### Increased Fuel Consumption

In Phase III, increased fuel consumption was treated as an increased cost. The Commission proposes 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 marginal system cost of the fuel will 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.

## 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. The Commission proposes no changes to this requirement for Phase IV. EDC evaluation contractors shall 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.

### Treatment of Incentives to Free-Riders

The Commission proposes 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. NTG research shall 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.*[[60]](#footnote-61)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.

### Treatment of NTG for TRC Benefits

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

## 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 Tentative Phase IV Implementation Order in spring 2020 and a Final Implementation Order in summer 2020. Stakeholders at this docket in response to this Tentative Order should comment on the proposed cost-effectiveness methodology for DR. This docket will not address issues related to whether DR should be included in or excluded from a potential Phase IV. Our discussion and proposal herein, as well as stakeholder comments at this docket, merely presume for discussion and comment purposes that Phase IV will include DR. Whether or not Phase IV includes DR targets, we are proposing guidance on how to calculate the TRC costs and benefits for DR in this order.

### 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.

For the 2021 TRC Test, we propose 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, 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.[[61]](#footnote-62) 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.[[62]](#footnote-63)

The Commission’s position is that Phase IV DR programs, if any, should be nominated to PJM as Peak Shaving Adjustments.  This position is 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. We recognize that Price Responsive Demand (PRD)[[63]](#footnote-64) is another potential avenue for Act 129 DR programs to be recognized at PJM.  However, based upon input from the Phase III SWE, we propose the Peak Shaving Adjustment mechanism may be the most appropriate path. Stakeholders are encouraged to provide comments on the proposal to nominate Phase IV Act 129 DR program reductions as Peak Shaving Adjustments as opposed to PRD or the Phase III design where Act 129 DR is not formally nominated to PJM.  Peak Shaving Adjustments 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 Peak Shaving Adjustments 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 Peak Shaving Adjustments 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 has provided PJM with hypothetical Pennsylvania data, and PJM is running an analysis using the Pennsylvania data but extrapolating from the BGE results.

Without Pennsylvania-specific data, we have reviewed the BGE data. Table 6, below, compares the non-coincident and coincident peak load forecasts for BGE zone in the January 2019 Load Forecast Report[[64]](#footnote-65) and the March 2019 Load Forecast Report[[65]](#footnote-66). The difference between the two forecast reports is the inclusion of the peak shaving adjustment for BGE zone. BGE nominated 390 MW of peak shaving, which factors in as an adjustment in Table 6.

Table 6: Summer Peak Load Forecast Impacts from BGE Peak Shaving Adjustment



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[[66]](#footnote-67) is lower, but our position is that the coincident peak demand forecast[[67]](#footnote-68) impacts are the relevant metric for capacity obligation and valuation of DR.

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

The Commission proposes that a similar perspective is 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 propose 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 = $14/kW-year should be used to calculate the avoided cost of transmission capacity from DR programs.

As in Phase III, the Commission proposes 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%. Like Phase III, we propose 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.

### 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 the 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[[68]](#footnote-69) 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 are proposing no changes in the 2021 TRC Test regarding the use of DR incentive amounts to estimate participant costs for Phase IV. EDCs will continue to use the 75% participant cost assumption.

### Measure Life

DR is a broad category of programs and measures that may or may not involve equipment installed at the participating customer 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, etc. For this class of DR programs, a measure life equivalent to the expected mechanical life of the equipment is appropriate.

When a multi-year measure life is assumed for demand, consistent with the 2016 TRC Test requirements, EDCs must 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 are not proposing a change to this provision for the 2021 TRC Test.

We also remind the EDCs that any DR equipment purchased in a previous phase cannot be included in the 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.”

# CONCLUSION

With this Tentative Order, the Commission seeks comments and reply comments on the proposed 2021 TRC Test intended for use in the potential Phase IV of Act 129. This Tentative Order represents the Commission’s continuing efforts to establish a comprehensive TRC Test, with the purpose of evaluating the EE&C programs pursuant to Act 129 during the potential Phase IV.

Comments and reply comments to this Tentative Order should reflect the topical numbering references as used herein. If your comments or reply comments do not address each specific topic from this Tentative Order, please include the notation that you are not commenting on a particular topic. If you are raising new topics, please do so after you have addressed the topics raised in this Tentative Order.

This Tentative Order and all filed comments and reply comments related to this Tentative Order will be made available to the public on the Commission’s Act 129 Information web page[[69]](#footnote-70); **THEREFORE,**

**IT IS ORDERED:**

 1. That a copy of this Tentative Order be served on the Office of Consumer Advocate, the Office of Small Business Advocate, the Commission’s Bureau of Investigation and Enforcement, the 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, all parties to *Implementation of the AEPS Act of 2004: Standards for the Participation of DSM Resources – TRM 2021 Update* at Docket No. M-2019-3006867, and *Release of the Act 129 [Phase III SWE] Energy Efficiency Baseline Studies*, Docket No. M‑2019‑3006866 (potential Phase IV docket).

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

 3. That interested parties shall have twenty (20) days from the date notice of this Tentative Order is published in the *Pennsylvania Bulletin* to file comments and thirty (30) days from the date notice of this Tentative Order is published in the *Pennsylvania Bulletin* to file reply comments at Docket No. M‑2019‑3006868.

 4. That comments and reply comments may be filed either electronically or in hard copy with the Pennsylvania Public Utility Commission, Attn: Secretary Rosemary Chiavetta, Commonwealth Keystone Building, Second Floor, 400 North Street, Harrisburg, Pennsylvania 17120.[[70]](#footnote-71)

 5. That this Tentative Order and all filed comments and reply comments related to this Tentative 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>.

 6. That a Word-formatted copy of all comments and reply comments shall be electronically mailed to David Edinger at dedinger@pa.gov and to Louise Fink Smith at finksmith@pa.gov. Attachments may not exceed three (3) megabytes.

7. That the contact person for technical issues related to this Tentative Order and the proposed 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 Tentative Order and the proposed 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: September 19, 2019

ORDER ENTERED: September 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 7 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 7: 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 5. 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 9. |
| Gross TRC benefits | $ | $$TRC Benefits\_{gross}$$ | *See* Table 9. |
| Gross TRC costs | $$TRC Costs\_{gross}$$ | *See* Table 9. |
| Net TRC benefits | $$TRC Benefits\_{net}$$ | *See* Table 9. |
| Net TRC costs | $$TRC Costs\_{net}$$ | *See* Table 9. |
| Electric energy benefits | $$ EB\_{t}$$ | *See* Table 9. |
| Capacity benefits | $$ DB\_{t}$$ | *See* Table 9. |
| Fuel benefits | $$ FB\_{t}$$ | *See* Table 9. |
| Water benefits | $$ H2OB\_{t}$$ | *See* Table 9. |

Algorithms

 TRC ratios, net benefits, and levelized costs are detailed in Table 8 below. While some of the inputs are available in Table 7, other inputs must be calculated. These input formulae are provided on the next page, in Table 9.

Table 8: 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 9: Supporting Algorithms

|  |  |
| --- | --- |
| $$NTGR$$ | $$=1-FR+SO+ME$$ |
| $$TRC Benefits\_{gross}$$ | $$=\sum\_{t=1}^{N}\frac{\begin{array}{c} \\EB\_{t}+FB\_{t} + H2OB\_{t}+ O\&M\_{t}\end{array}}{\left(1+d\right)^{t-1}}$$ |
| $$TRC Costs\_{gross}$$ | $$=\sum\_{t=1}^{N}\frac{PA\_{t} + IMC\_{t} - OI\_{t}}{\left(1+d\right)^{t-1}}$$ |
| $$TRC Benefits\_{net}$$ | $$=NTGR\*(TRC Benefits\_{gross})$$ |
| $$TRC Costs\_{net}$$ | $$= \sum\_{t=1}^{N}\frac{PA\_{t} + (IMC\_{t}- OI\_{t})\*(NTGR) }{\left(1+d\right)^{t-1}}$$ |
| $EB\_{t}$ (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

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

ME: Market Effects

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

PUC: Public Utility Commission

PVNB: Present value of net benefits

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.

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 Proposed Continuations/Changes/Clarifications/New Items**

|  |  |  |
| --- | --- | --- |
| **Sub-section** | **Subsection Name** | **Summary of Proposed 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 plan level, not program 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 EDCs’ 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. |
| **6** | Low-Income Programs | Continue reporting low-income programs as previously done. |
| **7** | Basis of TRC Test Impacts | Continue reporting net savings and describe how 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 propose that period is broken into three segments. Propose the use of specific futures markets based on territory served. |
| **3** | Nominal vs. Real Dollars | Continue to develop avoided costs forecasts in nominal dollars.Nominal discount rate to be used to calculate NPV. |
| **4** | Line Losses | Use 2021 TRM to calculate line losses. |
| **5** | Escalation Rate | Use BLS Electric Power GTD sector price index, compounded by average growth rate of average annual values of prior 4 years. |
| **6** | Avoided Cost of Generation Capacity | Change methodology for calculation. |
| **7** | Avoided Cost of Transmission and Distribution Capacity | Fundamental calculation to stay consistent, but order of operations would change. 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 | Propose 84 cents per MWh for first year of Phase IV and escalate yearly by BLS escalation factor. |
| **9** | Price Suppression Effects | Continue to exclude effects of Price Suppression in TRC calculations. |
| **10** | End Use Adjustments | Continue use of end-use profiles, when available. |
| **C - Other TRC Benefits** |
| **1** | Quantifying Water Impacts | Propose methodology to quantify water decreases/increases based on memo to EDCs in Phase III, not part of 2016 TRC Test Order. |
| **2** | Monetizing Water Impacts | Propose methodology to monetize water decreases/increases based on memo to EDCs in Phase III, not part of 2016 TRC Test Order. |
| **3** | Quantifying Fossil Fuel Impacts | Propose methodology to quantify fossil fuel decreases/increases based on memo to EDCs in Phase III, not part of 2016 TRC Test Order. |
| **4** | Interactive Effects | Propose that EDCs choose between two methods to estimate interactive effects of non-residential lighting. |
| **5** | Monetizing Fossil Fuel Impacts | Propose that EDCs 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.  Propose that EDCs use NG loss factor of 4%. |
| **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 | Propose that kits and directly installed equipment costs be treated 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 | Propose that kits and directly installed equipment costs be treated as an incentive to the customer. |
| **4** | Incentives from Outside of Act 129 | Propose that incentives from outside Act 129 be treated as reduction in costs, not as benefit to program. |
| **E - Fuel Switching** |
| **1** | ENERGY STAR Requirement | Propose that EE&C plans state proposed minimum performance standard and provide justification for fuel switching measures that have no ENERGY STAR performance standard. |
| **2** | Increased Fuel Consumption | Propose that increased fuel consumption be treated 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 2016 TRC Test ratios based on projected gross 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 proposed guidance to calculate TRC benefits and costs for DR is included.  Stakeholders should comment on proposed cost-effective methodology for DR. |
| **2** | Calculation of DR Benefits | Propose that EDCs average gross verified demand reductions over each hour of performance and apply line loss adjustment factor.  Propose that EDCs use 60% of avoided cost of G capacity 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 | Continue to apply measure life for DR equipment.  Clarify that DR equipment purchased in prior phase should not be counted in Phase IV. |

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. [↑](#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, as proposed, 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 Tentative 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 Tentative Order. [↑](#footnote-ref-18)
18. *See* <https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf>. [↑](#footnote-ref-19)
19. *See* <https://www.cbo.gov/system/files/2019-03/54918-Outlook-3.pdf> at pages 21-24. [↑](#footnote-ref-20)
20. *See* <http://www.puc.pa.gov/pcdocs/1057172.docx>. [↑](#footnote-ref-21)
21. *See* <http://www.puc.state.pa.us/pcdocs/1190750.docx> at page 4. [↑](#footnote-ref-22)
22. *See* <http://www.puc.pa.gov/pcdocs/1367195.docx> at page 66. [↑](#footnote-ref-23)
23. *See* <https://tradingeconomics.com/united-states/gdp-growth>. [↑](#footnote-ref-24)
24. *See* <https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf>. [↑](#footnote-ref-25)
25. *See* <https://aceee.org/files/proceedings/2014/data/papers/8-1084.pdf>. [↑](#footnote-ref-26)
26. *See* <https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf> page 91. [↑](#footnote-ref-27)
27. 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-28)
28. 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-29)
29. For instance, if the EDC EE&C plan is due in November 2020, the prompt month will be August 2020. [↑](#footnote-ref-30)
30. “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-31)
31. 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-32)
32. 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-33)
33. 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-34)
34. 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-35)
35. *See* <http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/technical_reference_manual.aspx>. [↑](#footnote-ref-36)
36. *See* <https://data.bls.gov/timeseries/PCU221110221110>. [↑](#footnote-ref-37)
37. 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-38)
38. 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-39)
39. 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-40)
40. Table 2 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-41)
41. *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-42)
42. *See* AEPS Act Historical Pricing reports at <https://www.pennaeps.com/reports/>. [↑](#footnote-ref-43)
43. *See* 71 P.S. § 714*.* [↑](#footnote-ref-44)
44. 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-45)
45. 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-46)
46. 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-47)
47. *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-48)
48. 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-49)
49. *See Energy Efficiency and Conservation Program* Tentative Order, Docket Nos. M-2012-2289411 and M-2008-2069887 (entered November 14, 2013). [↑](#footnote-ref-50)
50. *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-51)
51. Generally speaking, supply resources are increases in supply, and demand resources reduce demand for electricity from the power system. [↑](#footnote-ref-52)
52. 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-53)
53. *See* <http://www.waterrf.org/PublicReportLibrary/RFR90781_1999_241A.pdf> at pages 95-96, 100. [↑](#footnote-ref-54)
54. *See* <http://www.waterrf.org/PublicReportLibrary/4309A.pdf> at page 9. [↑](#footnote-ref-55)
55. Phase III SWE calculations using 2021 TRM assumptions. Note that water savings applies to the clothes washer only. [↑](#footnote-ref-56)
56. *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-57)
57. *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-58)
58. *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-59)
59. *See* <http://www.puc.state.pa.us/Electric/pdf/Act129/SWE_PhaseIII-Evaluation_Framework050818.pdf> at page 83. [↑](#footnote-ref-60)
60. *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-61)
61. *See* <https://www.pjm.com/committees-and-groups/task-forces/sodrstf.aspx>. [↑](#footnote-ref-62)
62. *See* <http://www.puc.state.pa.us/Electric/pdf/Act129/Act129-SWE_AR_Y9_022819.pdf> page 14. [↑](#footnote-ref-63)
63. For a definition of PRD 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-64)
64. *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-65)
65. *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-66)
66. The non-coincident peak load forecast is zonal, capturing only a specific EDC. [↑](#footnote-ref-67)
67. The coincident peak demand forecast reflects the relationship of a zone to the PJM footprint. [↑](#footnote-ref-68)
68. *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-69)
69. *See* <http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/total_resource_cost_test.aspx>. [↑](#footnote-ref-70)
70. *See* <http://www.puc.pa.gov/filing_resources.aspx> for filing instructions. [↑](#footnote-ref-71)