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December 30, 2013

<u>Via Electronic Filing</u>
Rosemary Chiavetta, Secretary
PA Public Utility Commission
PO Box 3265
Harrisburg, PA 17105-3265

Re: Energy Efficiency and Conservation Plan
Docket Nos. M-2012-2289411; M-2008-2069887

Dear Secretary Chiavetta:

Enclosed for electronic filing please find the Joint Comments of Demand Response Providers: Comverge, Inc., EnerNOC, Inc., and Johnson Controls, Inc., to Pennsylvania PUC Tentative Order of November 30, 2013 with regard to the above-referenced matter.

Sincerely,

Daniel Clearfield

Daniel Clearfield

DC/lww
Enclosure

cc: Megan Good at megagood@pa.gov
Kriss Brown at kribrown@pa.gov

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Energy Efficiency and Conservation Plan	:	Docket Nos. M-2012-2289411 M-2008-2069887

JOINT COMMENTS OF DEMAND RESPONSE PROVIDERS COMVERGE, INC. ENERNOC, INC. AND JOHNSON CONTROLS, INC. TO PENNSYLVANIA PUC TENTATIVE ORDER OF NOVEMBER 30, 2013

Pursuant to the procedural schedule set forth in the Pennsylvania Public Utility Commission's ("Commission") November 14, 2013 Tentative Order and the notice published on November 30, 2013 in the Pennsylvania Bulletin to file written comments in the above-referenced matter ("Tentative Order"), Comverge, Inc. ("Comverge"), EnerNOC, Inc. ("EnerNOC"), and Johnson Controls, Inc. ("JCI") (collectively "the DR Providers") respectfully submit their Comments to the Tentative Order in the above-captioned dockets. Specifically, these comments address: 1) the Energy Efficiency and Conservation ("EE&C") Program Statewide Evaluator's Amended Demand Response Study; 2) the proposed demand response program methodology for future phases of Act 129; and 3) the potential implementation of a demand response potential study and a wholesale price suppression study ("Comments"). The Act 129 Statewide Evaluator ("SWE") has generally done a thorough and thoughtful analysis of the issues relevant to procuring additional load reductions through Act 129 in the future. With a few of exceptions, the DR Providers support the recommendations of the SWE.

I. BACKGROUND

On August 2, 2013, the Commission adopted an Implementation Order that established the Phase II EE&C Program with incremental consumption requirements for each electric distribution company ("EDC") to meet by May 31, 2016.[1] In the Phase II Implementation Order, the Commission stated that it could not set additional peak demand reduction targets at that time since it did not have sufficient information regarding cost-effectiveness of the current or another peak demand reduction program.[2] The Commission directed the SWE to conduct a Demand Response Study to fully assess the costs and benefits of the current peak demand reduction programs.[3] On May 17, 2013, the Commission released the *Act 129 Demand Response Study – Final Report* ("DR Study") and then held a Demand Response Study Stakeholders' Meeting on June 11, 2013. The Commission directed the SWE to conduct a preliminary wholesale price suppression and prospective Total Resource Cost ("TRC") analysis of the peak demand reduction program. On November 1, 2013, the SWE completed its analysis in an Addendum to the DR Study. On November 14, 2013, the Commission adopted and entered a Tentative Order, releasing for comment the amended Act 129 Demand Response Study which included the Preliminary Wholesale Price Suppression and Prospective TRC Analysis ("Amended DR Study") prepared by the SWE assessing the cost-effectiveness of the Phase I peak demand reduction program.[4] The Commission also sought comments on an alternative peak demand reduction program to be studied for inclusion in a subsequent phase of the EE&C Program.

These Comments are submitted by three of the leading DR providers: Comverge is one of the nation's leading providers of energy management products and services. Comverge has been

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1 *See Energy Efficiency and Conservation Program*, Implementation Order at Docket Nos. M-2012-2289411 and M-2008-2069887, (*Phase II Implementation Order*) (Order entered August 3, 2012).

2 *Id.* at 32-42.

3 *See*, *Energy Efficiency and Conservation*, Docket No. M-2008-2069887 (Secretarial Letter dated March 4, 2011).

4 *See Act 129 Demand Response Study – Final Report*, Prepared for the Pennsylvania Public Utility Commission, GDS Associates, *et al.*, Submitted May 13, 2013, Addendum Added November 1, 2013, available at http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/act_129_statewide_evaluator_swe_.aspx.

an active Conservation Service Provider ("CSP") in Pennsylvania[5] and has served several EDCs who are in the Act 129 Phase I and Phase II Programs. Comverge has provided complex energy management programs and related services to small business, large commercial, and industrial customers throughout Pennsylvania. Comverge also provides utility companies with residential direct load control solutions. Comverge has a unique business model and extensive experience in providing energy management solution services to all types of customers.

EnerNOC , Inc. is the largest demand response aggregator in the world, actively integrating demand response resources, both bilaterally and into capacity, energy, and ancillary services markets across the United States, Canada, the United Kingdom, Australia, and New Zealand. EnerNOC, has been an active CSP in Pennsylvania and served several EDCs during Phase I of Act 129. In addition to demand response services, EnerNOC provides advanced energy management and supply procurement assistance to consumers around the world.

Johnson Controls, Inc. ("JCI") is a Fortune 100 company that integrates demand response services into its energy efficiency and building management businesses through the EnergyConnect subsidiary. JCI served several EDCs during Phase I of Act 129 and is an active CSP in demand response in markets in PJM, New York, California and Texas. EnergyConnect's award winning GridConnect platform is used by customers to provide improved and efficient grid services.

II. NOTICE OF SERVICE

All notices and services should be made on the following representatives listed below.

[5] Comverge is registered as a CSP on the PUC's Registry of CSPs. *Petition of Comverge, Inc.*, Docket No. A-2009-2113604, Secretarial Letter dated Nov. 3, 2011 approving application to re-register as a Conservation Service Provider. Comverge's wholly owned subsidiary, Enerwise Global Technologies, is also registered as a CSP. *Petition of Enerwise Global Technologies, Inc.*, Docket No. A-2012-2297625, Secretarial Letter dated April 11, 2012 approving the company's application to register as a Conservation Service Provider.

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III. DR PROVIDERS' JOINT COMMENTS

A. Proposed Amendments to the Residential Direct Load Control Programs

1. The Useful Life Of The Measure Equipment

In its Tentative Order, the Commission stated that, when performing TRC calculations, the useful life of the Direct Load Control ("DLC") measure equipment should be changed to the actual useful life of such equipment, which ranges from between eight (8) and ten (10) years.[6] The Commission added, "Increasing the measure life of the equipment would allow the Commission the flexibility to prescribe a DLC program over a number of years, which could increase the cost-effectiveness of these programs."[7]

It is the DR Providers' experience that the useful life of the relevant measure equipment is at least ten (10) years. The DR Providers agree the DLC measure equipment should be changed to the actual life of such equipment for the reasons stated by the Commission.

2. A Full Load Reduction Scenario Should Be Implemented To Determine Demand Savings

In Phase I, the demand savings for DLC programs were determined by averaging impacts from all hours within the top 100 hours of system demand, even if no curtailment event occurred. In a Full Load Reduction implementation, demand savings would be determined by multiplying the number of DLC devices by the average kW savings per device. The SWE concluded that this would be an appropriate savings calculation methodology because the value of the DR program is the EDC's ability to have load under control when needed.[8] Since the top 100 hours methodology leads to DR resources being called regardless of whether or not they would be cost-

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6 *Energy Efficiency and Conservation Program*. Docket Nos. M-2012-2289411 and M-2008-2069887 at 29 (Tentative Order entered November 14, 2013) ("*Tentative Order*")..

7 *Id.*

8 *Id.* (citing pages 41 and 42 of the Amended DR Study).

effective during those hours, the SWE recommended that this methodology should be discontinued for any future phases of Act 129 as it leads to predictive difficulties and low TRC ratios.[9]

The DR Providers agree with the SWE that a Full Load Reduction is the more appropriate evaluation approach for residential direct load control programs and that the 100 hours methodology applied in Phase I is not appropriate.

3. EDC-Purchased Phase I DLC Infrastructure Expenditures Should Be Considered Sunk Costs In Phase II

In Phase I, some EDCs, like PECO, purchased, and now own, the DLC devices installed in its territory. The SWE recommended that such an investment could be considered as a sunk cost for any future DLC programs before determining the cost-effectiveness of such programs.[10] Other EDCs, like PPL, leased the installed DLC devices so the costs would not be considered sunk and those EDCs would again have device purchase (or lease) and installation costs during any future DLC program.[11] The EDC can then try to achieve a net benefit relative to ongoing program costs for any future DLC program by excluding the sunk costs from the respective TRC calculations.[12]

The DR Providers do not see much of a distinction between purchased and leased DLC devices. DR Providers believe that the leasing model and the purchasing model lead to very similar cost structures over the long term. The analogy is similar to a person owning a car. It is not materially less or more expensive to purchase rather than lease a car. The procurement models have benefits for different buyers. The fundamental difference is that the leasing model shifts the economic, performance and market risk from the EDC to the CSP, much like leasing a

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9 *Id.* at 8.
10 *Id.* at 30; *See* page 56 of the Amended DR Study.
11 *See* page 44 of the Amended DR Study.
12 *See* page 43 of the Amended DR Study.

car puts all of the repair risk (because warranty periods typically align with lease terms) on the supplier of the leased vehicle (the car dealer).

In any financial evaluation, it is always important to recognize sunk costs when they exist. In the current Pennsylvania examples, if PECO were to conduct a TRC on extending its residential direct load control program, it would be inappropriate to include the capital cost of the existing control equipment because those "sunk" costs are irrelevant to a forward-looking analysis. Using the same line of reasoning, PPL may not need to consider the costs of the existing control equipment in its service territory because the capital cost is "sunk" to the lessors of the devices. PPL might have other start-up costs to consider in its TRC analysis and those would be appropriate for inclusion. While the dollars paid out over time may be similar under both models, the leasing model places more risks with the CSPs or providers of the leased equipment. Ultimately, therefore, the leased model is likely a better model for consumers in Pennsylvania.

4. Incentives Should Be Reduced For Any Future DLC Programs

The SWE reported that incentives paid by some of the EDCs in Phase I were higher than seen in other jurisdictions. The SWE suggested that by reducing incentives for any future DLC programs, such programs would be more cost-effective.[13] The DLC programs could become more cost-effective if administrative and incentive costs per kW are kept below the avoided generation and avoided transmission and distribution ("T&D") benefits per kW. The DLC programs could return a net benefit and potentially be continued.[14]

As a policy matter, the DR Providers do not object to reducing incentives. However, the DR Providers are compelled to point out that reducing incentives will likely decrease customer

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13 *Tentative Order* at 30; *See* pages 44 and 45 of the Amended DR Study.
14 *Id.*

participation, and possibly, the overall peak demand reductions attained. Comverge can aver that it has first-hand knowledge of what customers are willing to do from a demand response perspective based on certain incentives. While the SWE has stated that incentives vary from EDC to EDC, it has not performed any type of analysis on customers' receptivity to each level of incentive.

The DR Providers recommend, however, that any reevaluation of the level of incentive levels include consideration of a "pay-for-performance" incentive structure. The DR Providers note that with Advanced Metering Infrastructure ("AMI"), electrical meters can measure more refined levels of consumption and allow CSPs to calculate more precise levels of customers' load reduction. AMI also provides an advanced communication network to report the measurements in a much more timely manner. With full implementation of AMI, the DR Providers recommend a move from a fixed incentive model to a pay-for-performance model to make sure incentives are aligned with customers' performance and thus Act 129 programs can be more cost effective.

5. The Peak Demand Reductions From Any Future DLC Programs Should Be Bid Into The BRA And The Revenue Received Should Count As A Benefit In The TRC Test

The SWE recommends that, unlike in Phase I, the EDCs should be required to bid the peak demand reductions from their DLC programs into the PJM Base Residual Auction ("BRA") and the revenue received should count as a benefit in the TRC Test, effectively increasing the TRC ratio for those programs.[15]

The DR Providers do not object to the SWE's recommendation and look forward to collaborating with the EDCs in this regard in future DR Programs. However, the DR Providers offer two refinements to this suggestion. First, in order to maximize cost efficiency, the DR Providers recommend that the Commission move forward with approving Phase III DR

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15 *Tentative Order* at 30-31; *See* page 56 of the Amended DR Study.

programs and set attainable goals for each of the EDCs in relatively short order. PJM's annual BRA occurs in May every year and is for the PJM delivery year three years into the future. In other words, for the load reduction from the first year of a Phase III DR program to be offered into the BRA (reductions required by May 31, 2017), that capacity would have to have been offered to PJM in May 2013 in the BRA for the 2016/17 Plan Year. That capacity can be offered in future Incremental Auctions, but those Incremental Auctions have historically cleared at a lower price than the BRAs. The sooner that the Commission can mandate appropriate DR goals, the sooner the value recognized by the SWE can be captured for the ratepayers of Pennsylvania.

The DR Providers also recommend that the DLC Program offers should be made by the CSPs, and not the EDCs, in accordance with Act 129[16] and be a function of the market. Offering capacity into the PJM BRA imposes costs and risks on suppliers that should not have to be borne by EDCs or Pennsylvania ratepayers. For example, if the EDC DR programs were under-subscribed, the EDC might be penalized by PJM for failing to deliver the requisite amount of load drop. CSPs, who typically have larger portfolios of demand response obligations are better positioned to manage and hedge procurement risks. As noted, this approach is consistent with the mandates in Act 129 and is also consistent with other policies related to EDCs' participation in energy markets.

[16] Act 129, Section 2806.1 requires the EE&C Program to include: "Procedures to require that Electric Distribution Companies competitively bid all contracts with Conservation Service Providers." Also, Act 129, Section 2806.1 requires each EDC to develop an EE&C Plan whereby "The Plan shall include a contract with one of more Conservation Service Providers selected by competitive bid to implement the Plan or a portion of the Plan as approved by the Commission." 66 Pa. Cons. Stat. Ann. §§ 2806.1(a)(7) and 2806.1(b)(1)(i)(E) (West 2013). Thus, since the actual DR program is to be conducted by CSPs the offering of the DR Resource into the BRA should also be done by the CSPs.

B. Proposed Amendments to Commercial and Industrial Load Curtailment ("LC") Programs

1. Further Research Should Be Conducted To Determine Avoided T&D Costs In Each EDC Territory And That These Costs Be Included In The Cost-Benefit Determinations Of Future LC Programs

The SWE did not include avoided T&D costs in its cost-benefit TRC calculations for the Phase I LC programs in each EDC territory due to difficulties in estimating such costs. As a result, the SWE recommended further research to develop better estimates.[17]

Avoided T&D costs are an important aspect in the cost-benefit analysis and cannot be ignored since they can provide real benefits to ratepayers and EDCs. The DR Providers agree that more research is needed to determine the appropriate level of avoided T&D costs. Inclusion of such costs will only improve the cost-effectiveness of any future Act 129 DR program.

2. The Commission Should Consider Dual Participation In The Act 129 DR Programs, As Well As PJM's Emergency Load Response Program ("ELRP"), When Implementing Any Future LC Programs

The SWE recommended that the Commission should consider dual participation in the Act 129 DR programs, as well as PJM's ELRP, when implementing any future LC programs. Specifically, the SWE suggested that the Commission should ensure that such future LC programs provide incremental value to the competitive markets already in place.[18] The SWE recognized that, in Phase I, many commercial and industrial customers participated in the Act 129 DR programs, as well as PJM's ELRP.[19] The SWE noted that if PJM has already secured capacity from a customer, that customer's participation in an EDC's Act 129 LC program may offer little or no additional value. The SWE noted, however, that it is possible that a customer

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17 *Tentative Order* at 31-32.

18 *Tentative Order* at 32; *See* page 56 of the Amended DR Study.

19 *Tentative Order* at 31.

may not have enrolled in the PJM program if the revenue stream from the Act 129 LC program was not available.[20]

The DR Providers submit that the Act 129 DR programs and the PJM's ELRP are distinct and independent, and should not be subject to an either/or decision. Accordingly, the DR Providers recommend that both programs should be offered to customers independently. The PJM Demand Response program was designed to help PJM reduce demand during system constraints. The Act 129 programs were designed to help Pennsylvania EDCs reduce consumption during peak hours to remediate high energy prices for consumers. The PJM program is essentially a federal program while the Act 129 Program is a state program.

Moreover, there is not a perfect correlation between PJM emergency DR event days and either customer-specific or coincident system peak hours. This should be unsurprising, as the programs are intended, as noted above, to target different things. PJM system emergencies can occur during peak periods, but they can also occur during shoulder peak periods, as indeed occurred in September 2013. Meanwhile, PJM economic activity can also take place during peak periods, but that correlation is not perfect either. In addition, as EnerNOC and others noted in previous comments, much of the economic DR activity that occurred in conjunction with Phase I took place *because* of the PJM economic activity. CSPs were forced to offer reductions into the PJM economic program concurrent with Act 129 reductions or face erosion of the customers' peak load contributions ("PLCs") that would impair their ability to participate in PJM emergency DR during the summer of 2013. In effect, absent overlapping participation in economic DR, CSPs would have been faced with the same "either/or" choice that DR Providers counsel against here.

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[20] *Tentative Order* at 31-32; *See* page 48 of the Amended DR Study.

There are numerous analogous situations in which consumers can receive simultaneous benefits with dual incentive programs. For example, in certain circumstances, a consumer can receive a federal income tax deduction while at the same time receiving a state income tax deduction for the same item. Over the past several years, certain renewable energy and energy efficiency programs have permitted customers to receive incentives from multiple sources including federal grants, state grants, utility rebates, accelerated depreciation and no interest loans. Such incentives work together and can be the determining factor for a customer. If there is a financial incentive offered, it follows that new customer participation increases. There is no reason why the Commonwealth should put any constraints on dual participation, because there are dual benefits and it could never be known with certainty what ultimately motivated a customer to participate in either or both programs.

DR Providers are sensitive to the concern that customers only pay once for each service, but the Commission needs to recognize that when two services are being provided, and there is no way to be sure ahead of time that both will overlap, it is appropriate to pay for those services separately.[21]

C. Potential Demand Response Methodology

1. The Use Of Day-Ahead Forecasting

As an alternative to the top 100 hours program, the SWE suggested two potential models for requiring demand reductions. The first methodology was a cost-based model that suggests that whenever energy prices reach a certain threshold, that load curtailments be called. The

[21] DR Providers commend to the Commission the recent filing by the Consolidated Edison Company to greatly enhance its payments to CSPs for DR used to avoid network emergencies and to reduce system peaks. Payments under these programs are not only additive between each other (because they obligate participants to provide ConEd with two different services), they are also additive to the NYISO Special Case Resources emergency DR program, because that program seeks yet different services. The ConEd approach should be the model for treatment of overlapping program participation, just as it is for the mechanism for dispatching DR under Act 129. A copy of the recent ConEd filing is provided for the Commission's consideration as Attachment 1.

second methodology was a model that compared the EDC's day-ahead load forecasts with the EDC's annual peak load forecasts. If the day-ahead forecast was a certain percentage of its peak, then load reductions would be called. The DR Providers strongly support the second of these two approaches.

The cost-based approach has many flaws from a market and a reliability perspective. Similar to the top 100 hours approach, the DR Providers believes that a price-based approach will result in needless and ineffective demand response curtailments. Costs can rise for many reasons – only one of which is constrained capacity. It may or may not be appropriate to call curtailments because prices reach certain levels. Electricity prices could rise in the winter in response to a crisis or conflict in some part of the world that affects world energy prices. In this scenario, demand response would neither be appropriate nor effective (if even available). Historically, prices are typically "highest" in the summer. They can be "high" any time of the year. Also, depending upon where the price threshold is set, the system could be constrained and prices may not reach that mark set by this regulatory process. In that scenario, the state would not be getting the curtailments it needs, but will be paying for.

The DR Providers are strong advocates of the SWE's recommended methodology of comparing the day-ahead forecast to the EDCs forecasted summer peak. If the day-ahead forecast reaches some percentage (to be determined) of that peak, then the EDCs would call for load curtailments. The statutory goal for peak load reductions for Phase III is a reduction of some percentage (the level still to be determined) from the peak from the 2011/12 Plan Year.[22] The DR Providers suggest that the Commission incorporate those requirements when developing a set of curtailment parameters.

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22 66 Pa. Cons. Stat. Ann. § 2806.1(d)(2) (West 2013).

The objectives of Act 129 were primarily to give customers tools to control energy expenses. The DR Providers believe that the Demand Response programs put in place in the Phase I implementation were appropriate, but the top 100 hours requirement was a flawed approach (albeit statutorily required). Now, however, the Commission has full flexibility to develop the curtailment requirements for future Demand Response programs. The DR providers strongly urge the Commission to choose a methodology that is based on peak load and load reduction requirements rather than one based on nothing other than costs. High electricity prices can be caused by many factors. On the other hand, constrained capacity nearly always results in appropriate price signals. Act 129 Programs should be targeted at reducing the impact to consumers from capacity constraints.

2. The Treatment Of C&I Customers Potentially Enrolling In Both The Act 129 DR Program And PJM's ELRP Or Similar Program

In the SWE's proposed DR model, C&I customers enrolled in the PJM's ELRP would not be eligible to participate in the Act 129 DR programs.[23] The DR Providers disagree with the SWE's position. As discussed more fully above, the programs are distinct and independent of each other.

Additionally, for residential programs, the SWE has suggested that the load drop be offered into the BRA; as stated above, this recommendation is totally appropriate and will increase the TRC benefits to customers significantly. What that means, however, is that the residential customers would be participating in both the PJM ELRP program and the Act 129 load reduction programs. It is not reasonable to suggest that it is appropriate for residential customers to benefit from both programs but at the same time suggest that C&I customers cannot do the same. The SWE should evaluate the program as if it were a stand-alone program. If a

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[23] *Tentative Order* at 32.

customer also participates in the PJM program, then incremental benefit should be ascribed to the program, just as is suggested for the residential programs.

The SWE's proposal appears to be that (1) dual participation in the PJM Emergency Load Response Program and Act 129 Peak Load Reduction initiatives would not be allowed; and (2) that Act 129 would be designed to pay less than the PJM ELRP. The necessary consequence of such a formulation, particularly in the face of expected dispatches in ELRP that are less frequent than is likely to be the case under Act 129, is that no rational customer capable of participating in both programs would choose to participate in Act 129. This is a recipe for failure.

3. The Treatment Of Certain Phase I DLC Costs As Sunk Costs

The SWE proposes to have purchased DLC equipment be considered sunk costs and excluded from TRC calculations.[24] As discussed above, the DR Providers do not object to treating certain Phase I DLC capital expenditures as sunk costs; however, they do not see much of a distinction between purchased and leased DLC devices, as stated earlier for the residential customers.

D. Demand Response Potential and Wholesale Price Suppression Studies

1. Demand Response Potential Study

The Phase II SWE contract includes an optional Demand Response Potential Study work plan. The Commission stated, "this study will provide more definitive cost-effectiveness information regarding the proposed DR methodology ..., as well as information regarding any potential peak demand reduction targets."[25]

The DR Providers support the SWE's recommendation to conduct such a DR Study and to do soon an expedited basis.

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24 *Tentative Order* at 33.
25 *Tentative Order* at 34.

2. Wholesale Price Suppression Study

The SWE's wholesale price suppression information is in its preliminary stages as it has provided only preliminary estimates of wholesale price suppression resulting from Phase I and from potential future DR programs. For a more definitive approach, the Commission proposes that the SWE perform a full wholesale price suppression study which would provide in-depth supply curve modeling to determine the benefits to wholesale prices from Act 129 DR programs.[26]

The DR Providers support the SWE's recommendation to conduct such a wholesale price suppression study. The DR Providers suggest that the study should look at both wholesale capacity and energy price suppression. The Commission has the authority to request all of the requisite data needed to conduct such a study from both PJM and the Independent Market Monitor (under an appropriate protective agreement) and it should do so without delay.

[26] *Tentative Order* at 34.

IV. CONCLUSION

The DR Providers appreciate the opportunity to offer comments to the Statewide Evaluator's Amended Demand Response Study, the proposed demand response program methodology for future phases of Act 129 and the potential implementation of demand response potential and wholesale price suppression studies. The SWE has generally done a thorough and thoughtful analysis of the issues relevant to procuring additional load reductions through Act 129 in the future. With a couple of exceptions, the DR Providers support the recommendations of the SWE. The DR Providers look forward to working cooperatively with the Commission, the EDCs and other interested stakeholders in this proceeding to develop a new load reduction program that provides cost-effective load reductions to consumers in the Commonwealth.

Respectfully submitted,

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Attachment 1

conEdison
a conEdison, inc. company

Consolidated Edison Company
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www.conEd.com

December 18, 2013

Honorable Kathleen H. Burgess
Secretary
New York State
Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223

RE: CECONY Riders P, S, U, V and W

Dear Secretary Burgess:

Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") is filing with the Public Service Commission ("Commission") amendments to its Schedule for Electricity Service, P.S.C. No. 10 – Electricity (the "Tariff"), applicable to its customers in the City of New York and the County of Westchester. The Tariff leaves, which are identified in Appendix A, have a proposed effective date of April 1, 2014.

<u>Reason for Filing</u>

The Company is proposing changes to two of its tariffed Demand Response programs: the Commercial System Relief Program ("Rider S" or "CSRP") and the Distribution Load Relief Program ("Rider U" or "DLRP"). The Company is also proposing minor changes to programs that it activates at the request of the New York Independent System Operator ("NYISO"): the Purchases of Installed Capacity Program ("Rider P" or "ICAP") and the Emergency Demand Response Program ("Rider V" or "EDRP"). The Company is further proposing a housekeeping change to the Day-Ahead Demand Reduction Program ("Rider W" or "DADRP"), under which aggregated load is bid into the NYISO.

In the current filing, the Company is proposing changes to Rider S and Rider U to:

- clarify and/or streamline tariff language;
- make Rider S language consistent with similar provisions in Rider U;
- change program definitions affecting the terms of service; and

- modify program rules to increase customer participation and encourage improved customer performance during demand response events.

The Company also proposes changes to clarify and streamline tariff language in Riders P, V and W.

Tariff Changes Proposed

Major changes to the Riders are described below. Additional changes are described in Appendix B.

Rider S - CSRP

Rider S is available to Direct Participants (i.e., Customers who enroll under this Rider directly with the Company for a single Con Edison account and agree to provide at least 50 kW of Load Relief) and to Aggregators (i.e., parties other than the Company that represent and aggregate the load of Customers who collectively have a Load Relief potential of 100 kW or greater and are responsible for the actions of the Customers they represent) in the NYISO Zone J. Rider S includes a Summer Reservation System Relief Program (renamed the "Reservation Payment Option") and a Voluntary System Relief Program (renamed the "Voluntary Participation Option").

In order to foster enrollment and higher participation, the Company is proposing to increase the incentive rates available to Direct Participants and Aggregators and, in conjunction, reduce the criteria that limit participation. Under the Reservation Payment Option, the Company proposes to increase the capacity payment rate for Planned Events from $5.00 to $20.00 per kW per month for four or fewer events and from $10.00 to $25.00 per kW per month starting in a month with five or more events and continuing in the remaining months. The payment rate for participation during Unplanned Events is proposed to be changed from $5.00 per kW to $6.00 per actual kWh of Load Relief in each event hour. Unlike the current per-kW payment for Unplanned Events, payment made on a per-kWh basis will reimburse Direct Participants and Aggregators for participation during each additional event hour and encourage their participation for as many hours as requested by the Company. The Energy Payment (renamed the "Performance Payment"[1]) under the Reservation Payment Option is proposed to be increased from $0.50 to $1.00 per kWh.

Under the Voluntary Participation Option, the Company proposes to increase the payment rate from $1.50 to $6.00 per kWh for Load Relief during a Planned Event and from $5.00 to $20.00 per kWh for Load Relief during an Unplanned Event. In addition, the Company has eliminated the minimum payment threshold for Voluntary Performance payments, so as to reward Direct Participants and Aggregators for their efforts to reduce load when requested.

[1] The payment name was revised to more closely align this payment structure with the fact that it rewards customers for actual performance, without considering a customer's kW of contracted Load Relief.

In conjunction with increases to the payment rates, the Company is proposing revisions to reduce the penalty for non-performance under the Reservation Payment Option from two times the Reservation Payment Rate to one times the Reservation Payment Rate. Based on Aggregator survey results and the Company's discussions with Aggregators, reducing the penalty will help to increase customer enrollment.

In addition, the Company is introducing a Three-Year Incentive Payment under the Reservation Payment Program for both Direct Participants and Aggregators, for their customers, payable after they have successfully participated for three consecutive Capability Periods. Under the Three-Year Incentive Payment, Direct Participants and Aggregators, per customer, will receive a payment of $2.00 per kW per month, in addition to the Reservation Payment, applied to the kW levels that were used to calculate the monthly Reservation Payments during the applicable Three-Year Incentive Period. This incentive payment is intended to encourage customer re-enrollment from year to year and customer performance during events, which is expected to improve the accuracy of demand response capability forecasting by the Company.

As part of the Company's effort to align this Rider with the experience gained from program operation, the Company is proposing that the Capability Period under this Rider (which commences May 1) end on September 30, rather than October 31. There have historically been no CSRP events in October, and shortening the duration of the Capability Period allows the Company to raise the monthly Reservation Payment while maintaining the cost effectiveness of the program.

Additionally, the Company is proposing to redefine the term "Contracted Hours" from a five-hour period to a four-hour period to allow for better customer performance, lower the barrier to program participation, and help leverage the use of technology (such as batteries) that can supply four hours of load relief where five hours are not possible. This change is supported by the Company's findings from the Aggregator survey and from interactions with industry participants. For Customer planning purposes, the Company will post to its website by January 1, instead of February 1, the Contracted Hours applicable to specific networks for the upcoming Capability Period. Also, the Contracted Hours for Planned Events for SC 11 customers who export power to the Company will be the hours of 2:00 PM to 6:00 PM. Because the Company considers participating SC 11 customers to be a supply resource instead of a demand resource, the Company will utilize SC 11 customers' Load Relief to help relieve stress on the system during system-wide peaks, irrespective of the specific network peak time.

To ease administration of the program by facilitating the notification process, tariff language was added to allow the Company to provide notification by machine-readable electronic signal. Language was also added to allow for data review of any Capability Period, thereby allowing the Company to review data from previous Capability Periods and adjust for payment if necessary.

Finally, because the benefits to customers, benefits to the reliability of electric service, and benefit-to-cost ratio of the program increase with increased participation, the Company is proposing to eliminate the 200,000 kW participation limit under this Rider.