BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)	Case No. 14-1297-EL-SSO

SECOND SUPPLEMENTAL TESTIMONY OF MATTHEW WHITE

On behalf of Interstate Gas Supply, Inc.

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please introduce yourself.

A. My name is Matthew White. I am employed by Interstate Gas Supply, Inc. ("IGS" or "IGS Energy") as General Counsel, Legislative and Regulatory Affairs. My business address is 6100 Emerald Parkway, Dublin, Ohio 43016.

Q. Are you the same Matthew White that filed testimony on behalf of IGS earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Third Supplemental Stipulation filed in this proceeding on December 1, 2015 ("Third Supplemental Stipulation"). IGS has previously filed testimony opposing FirstEnergy's proposal to implement Rider RRS which would guarantee cost recovery, plus a significant rate of return, on approximately 3,000 MW of FirstEnergy Solutions ("FES") aging generation units. IGS continues to oppose approval of Rider RRS; moreover additional provisions contained in Third Supplemental Stipulation are actually worse for customers and the competitive markets than FirstEnergy's ESP application as filed. Specifically:

- The Third Supplemental Stipulation would adopt Rider RRS, the economics of which have gotten worse, given the significant decline in natural gas prices since FirstEnergy originally filed its original Application. Thus, it is becoming increasingly obvious that approving Rider RRS will have a significant adverse economic impact on Ohio ratepayers;

- The Ohio General Assembly has adopted a competitive retail electric structure and abandoned monopoly regulation as the means to procure electric generation service. Yet the provisions in the Third Supplemental Stipulation would allow for a regression towards re-regulation. Further, <u>there are no additional provisions the Third Supplemental Stipulation that would off-set the damage done to the competitive market, or that otherwise can be said to benefit competition in Ohio</u>;
- Not only is Rider RRS anti-competitive, and would thwart the will of the General Assembly, there are a number of *additional* provisions in the Stipulation that would harm customers by adding costs that would largely go to benefiting only FirstEnergy. With the additional provisions in the Stipulation, it appears that the Third Supplemental Stipulation is more lucrative for FirstEnergy than had the Commission simply approved FirstEnergy's application as filed.

For these reasons, in my testimony I explain that the Commission should not approve the Third Supplemental Stipulation, as it would approve an uneconomic and anti-competitive Rider RRS. Further, the additional provisions in the Third Supplemental Stipulation do nothing to mitigate Rider RRS and would actually compound the damage done to competitive markets and customers.

Q. If the Commission approves the Third Supplemental Stipulation, are there modifications to the ESP that you recommend?

A. Yes. In my Direct Testimony filed in this proceeding, I recommended that the Commission approve a number of retail electric enhancements that would mitigate the impact of anti-competitive elements in FirstEnergy's ESP application. Specifically I recommended:

- Unbundling SSO costs that are recovered through distribution rates and charge the SSO all costs required to provide retail electric service in the market as required by Ohio statute;
- Requiring FirstEnergy to end its discriminatory practice of allowing only select third party companies to bill for non-commodity charges on the electric distribution ("EDU") bill, and allow CRES providers to also bill for non-commodity charges on the EDU bill;
- Starting a process to initiate supplier consolidated billing ("SCB") that would allow CRES providers to issue a consolidated bill directly to the customers that includes generation charges and distribution charges.

If the Commission approves the Stipulation, I recommend that at a minimum the Commission also approve the retail enhancements described in my testimony to mitigate the adverse impact the Third Supplemental Stipulation will have on competitive markets and customers.

II. <u>TESTIMONY</u>

1. The Economics of Rider RRS Continue to Get Worse

Q. Have natural gas trends over the last year harmed the economics of Rider RRS for customers?

A. Yes. The marginal price of electricity is often set by the price of gas fired generation. Further, the price of gas electric generation is highly correlated with the price of natural gas. Thus, there is a strong correlation between natural gas prices and electric prices. Even since FirstEnergy has filed its original ESP Application, natural gas production in the region has continued to increase and natural gas prices have continued to decline. These trends have led to a fundamental and lasting shift away from coal and nuclear generation, towards natural gas generation. Thus, approval of Rider RRS would force FirstEnergy ratepayers to place a giant long-term bet on coal and nuclear generation when it is becoming increasingly obvious that this type of generation (particularly coal) is, and will be, uneconomical for the life of Rider RRS.

Q. Is your company familiar with the natural gas markets in Ohio?

A. Yes. IGS has been buying and selling natural gas in Ohio for over 25 years. In the mid-1980s, IGS started out as a natural gas supplier selling to large industrial customers in Ohio. IGS has since expanded its geographic footprint and now sells natural gas in multiple states throughout the Midwest and other areas of the country to residential, commercial, and industrial customers. IGS also has extensive experience buying, selling, transporting, and storing natural gas on pipelines throughout the Northeast, Midwest, and Gulf regions.

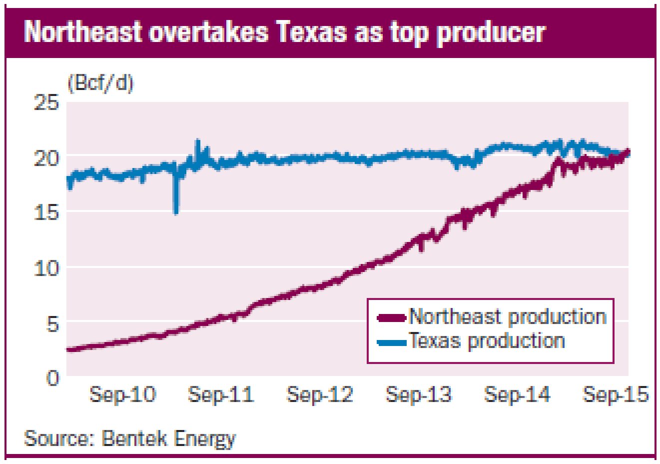
Q. Can you summarize the trends in the Ohio natural gas market that have intensified over the last two years?

A. Yes. Put simply, with the development of horizontal drilling and hydraulic fracking technologies, natural gas in our region has become significantly more abundant, much less costly to extract, and increasingly accessible. This fundamental shift in the natural gas markets has resulted in lower natural gas prices and much less price volatility even since FirstEnergy filed its original ESP application. Further, as I explain below, this trend towards lower gas prices and less volatility will likely only continue for a long time in the future.

Q. What are the reasons to believe that the trend toward less volatility in Ohio natural gas prices is likely to continue?

A. The amount of natural gas production throughout the United States has increased substantially even over the last five years. Further, much of that production has come from the Marcellus shale, which is located in Pennsylvania, West Virginia, New York, and to a lesser extent, Ohio. In fact, as shown in Figure 1, according to a Bentek Energy report published in Platts Gas Daily, the Northeast surpassed Texas as the largest production region in the US by producing 20.37 BCF and is expected to average 21.1 BCF/day through the end of the year.

Figure 1

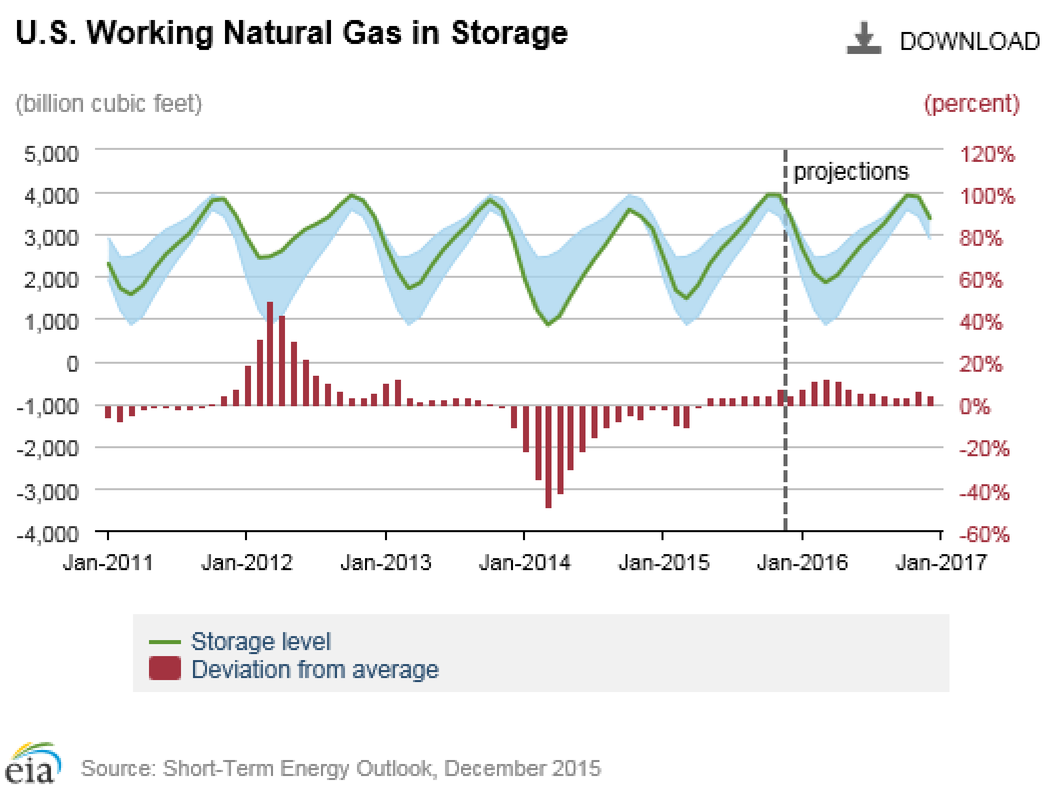


This increased production in and around Ohio has not only led to decreased prices, but it has also led to decreased volatility in natural gas markets given there are more opportunities to deliver gas from diverse range of sources. Thus, volatility in natural gas prices has decreased substantially even over the last few years. Moreover, given the long term trends in natural gas markets, this decreased volatility in natural gas pricing is likely to continue for the foreseeable future. Further, Bentek indicates the Northeast region, on an annual basis, has recently moved from a net importer of natural gas to a net exporter. In fact, Bentek projects in the Northeast will be exporting roughly 10 BCF/day out of the Northeast region by 2020.

Q. **Does storage inventory data also indicate lower expected volatility in the natural gas markets?**

A. Yes. Natural gas storage plays an important role in price volatility. This year the natural gas industry had the largest storage balance in history at above 4 TCF. As you can see from the latest EIA graph below (taken from the December 8, 2015 Short Term Energy Outlook[1]), Figure 2, not only will the balance this year be a record but the US will struggle to not break another record next year.

Figure 2



Q. Was the polar vortex prices indicative of volatility expected in the future?

A. No. First, it is important to keep the polar vortex in perspective. The polar vortex was the coldest winter that Ohio had experienced in over thirty years.[2] While there was increased volatility during that winter, the average daily Henry Hub

[1] https://www.eia.gov/forecasts/steo/report/natgas.cfm

[2] In Ohio, according to NOAA's monthly statewide temperature reporting, the winter of the Polar Vortex, defined as October, 2013 through April, 2014, was the coldest winter in the last 30 years, where the temperature for each winter is defined as the average of the monthly average temperatures reported by NOAA in each winter. This past winter in Ohio, as defined as October, 2014 through April 2015, was the third coldest winter in the last thirty years. Source: http://www.ncdc.noaa.gov/cag/.

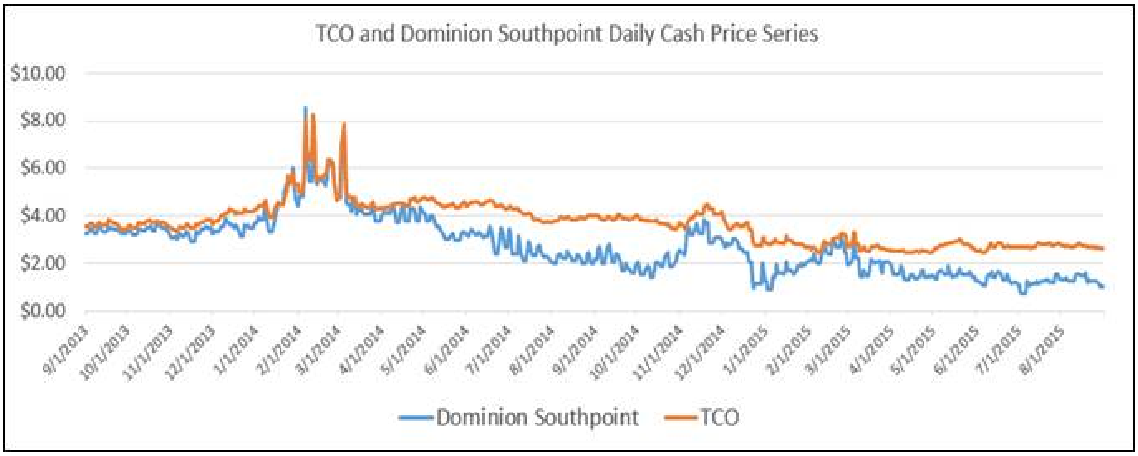
Spot Price, as referenced by the EIA for the period November 2013 through March 2014, was still only $4.68 per mmBTU for the winter.[3] Also, much has changed in the Ohio gas markets even since the polar vortex. Production in the Marcellus and Utica shale regions has increased substantially. Additional pipeline has also been added which has increased liquidity in the markets and reduced daily and geographic volatility. Again, we saw this decreased volatility play out during the 2014-2015 winter which was nearly as cold as the 2013-2014 winter where we experienced the polar vortex.

Q. Has volatility also been reduced at Ohio specific trading hubs?

A. Yes. The Columbia Gas Pool (also known as TCO IPP) is generally considered the most liquid trading hub for supplies moving into Ohio. Columbia has over a thousand miles of pipeline in Ohio with hundreds of physical interconnects along with over 100 BCF of underground storage capacity in Ohio. Depending on specific plant location, some facilities receive supplies from Dominion Transmission which has a liquid trading point called the Dominion South Point pool. As you can see from Figure 3, which shows the daily midpoint cash prices as defined by Platts Gas Daily, both TCO & Dominion South Point did in fact see elevated prices and increased volatility during the polar vortex winter. During the following winter, however, which was only marginally milder, there was dramatically reduced volatility and very little price increases especially during the extreme cold periods of January and February 2015.

[3] Source: Source: http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm

Figure 3



Q. Is lower natural gas prices leading to the build of new electric generation?

A. Yes. The ability to extract an abundant supply of low cost natural gas in the region is leading to the construction of numerous natural gas generation units. It's my understanding that currently there are at least 5 projects to add natural gas capacity *right here in Ohio*.[4] That is what happens when technological advancement occurs. New, more efficient technology replaces older less efficient technology. And when governmental entities try to disrupt this cycle by artificially intervening in the markets, it almost always leads to higher costs for consumers and slower technological advancement.

[4] Currently there is a 799 MW Oregon Clean Energy plant under construction in Oregon, Ohio. Also, there is a 700 MW plant under construction in Carrolton, Ohio. Advanced Power also announced it will construct a second facility in this area, named the South Field Energy facility, totaling an additional 1,100 megawatts. There is also a 500 MW NTE Energy plant in Middleton, Ohio that will be under construction. Further, Tenaska has announced plans to convert its 850 MW peaking plant into a 1,414 MW combined cycle plant in Vincent County, Ohio. Finally, Clean Energy Future announced plans to build an 800 MW plant in Lordstown, Ohio.

Q. Is it a prudent policy decision to lock Ohio ratepayers into supporting FirstEnergy's most uneconomic generation given the trends in the natural gas and electric generation markets?

A. No. To accept FirstEnergy's Rider RRS proposal would require the Commission to completely ignore the long term shift in electric generation toward natural gas. This is particularly true given Ohio is located so close to such an abundant supply of natural gas. Adopting Rider RRS would require FirstEnergy ratepayers to place a giant bet on aging coal and nuclear generation in the midst of a natural gas revolution that is increasingly making coal generation less competitive. Accepting FirstEnergy's proposal would be analogous to requiring FirstEnergy ratepayers to make a large investment in the horse and buggy industry just as Henry Ford was rolling out the Model T.

2. The Third Supplemental Stipulation Would Be a Step Backwards for Electric Competition in Ohio

Q. Does the Third Supplemental Stipulation benefit competitive retail electric markets?

A. No. In my initial testimony filed in this proceeding, I explained that allowing FirstEnergy to enter into power purchase agreements ("PPAs") with its affiliate FirstEnergy Solutions ("FES") would be a significant step backwards for competitive retail electric markets. That is why I proposed in my initial testimony that in order to mitigate the damage to the competitive retail electric markets, the

Commission adopt provisions to enhance competitive retail markets, including, but not limited to:

- Unbundling SSO costs that are recovered through distribution rates and charge the SSO all costs required to provide retail electric service in the market place as required by Ohio statute;
- Requiring FirstEnergy to end its discriminatory practice of allowing only select third party companies to bill for non-commodity charges on the electric distribution ("EDU") bill, and to allow CRES providers to also bill for non-commodity charges on the EDU bill;
- Starting a process to initiate supplier consolidated billing ("SCB") that would allow CRES providers to issue a consolidated bill (that includes generation charges and distribution charges) directly to the customers.

Q. Does the Third Supplemental Stipulation adopt any provisions that would enhance the competitive retail electric market?

A. No. <u>There are no provisions in the Third Supplemental Stipulation that would materially benefit the competitive retail electric market during the duration of the ESP.</u> In fact, there are a number of additional provisions in the Third Supplemental Stipulation that would actually harm competition, beyond just authorizing approval of the anti-competitive rider RRS.

Q. What additional provisions in the Third Supplemental Stipulation beyond rider RRS pose a threat to competitive retail electric markets and risk moving backwards toward re-regulation?

A. There are a number of *additional* provisions in the Third Supplemental Stipulation that would be harmful to competitive retail electric markets. Specifically:

- Provision E(4) contemplates FirstEnergy developing 100 MW of renewable energy resources and recovering those costs through a non-bypassable renewable resources rider. This provision (which was not contemplated in the original ESP application) contains the same anti-competitive aspects of Rider RRS and it represents a return to the electric distribution utility owning regulated generation. Further, this provision is particularly egregious because there are numerous companies willing to develop and own renewable projects; and there is no reason to hand the ownership of those projects over to the electric distribution utility. To the extent the Commission believes it reasonable to subsidize renewable generation, the Commission should make renewable incentives available on a competitively neutral basis. Adopting provision E(4) will send a signal to the renewable energy business community that Ohio is *not* open for business, but rather Ohio is more interested in just giving hand-outs to its incumbents.
- Provision C(3) contemplates the Commission opening a docket to address Ohio's long term generation resource adequacy needs. However, all of the Ohio's electric utilities have divested, or have been ordered to divest, their electric generation assets to un-regulated competitive companies. Therefore, the regulated electric distribution companies (over which the Commission has jurisdiction) are not in the business of owning electric generation. If the Commission were to take measures to address resource adequacy that would

necessarily mean the regulated utilities would be required to get back into the electric generation business either by directly owning electric generation assets, or indirectly, by anti-competitive mechanisms such as utility affiliate PPAs. This is a dangerous precedent to set and should not be contemplated, especially given that the notion of state-specific generation is fundamentally at odds with the physical operation of the PJM Interconnection transmission grid, which maintains *regional* reliability regardless of the location of any specific generation unit.

- Provision A(1) of the Third Supplemental Stipulation would extend the ESP period from May 31, 2019 to May 31, 2024, locking the provisions in FirstEnergy's ESP, and Third Supplemental Stipulation, for a period of 8 years. As I already noted in this testimony, the Third Supplemental Stipulation and FirstEnergy's ESP, as a whole, are anti-competitive. Historically, the Commission has used ESP proceedings to adopt pro-competitive provisions and to move competitive electric markets forward in accordance with Ohio Statute and the intent of the Ohio legislature. The adoption of provision A(1), however, would lock in an anti-competitive ESP and would substantially limit the CRES community to advocate for any changes that would enhance the competitive market for a period of 8 years.
- Provision G of the Stipulation would effectively eliminate the possibility of FirstEnergy filing a base distribution rate case for a period of 8 years; thus the CRES community would be foreclosed from advocating for enhancements to the competitive retail electric market in a base distribution rate case for 8

years as well. The lack of channels for retail advocacy (via the foreclosure of an ESP or distribution case for 8 years) will make it difficult for needed changes to be made to competitive retail electric markets in order for customers to realize the full benefits of competition. This problem is compounded by the fact that the Ohio Market Development Working Group ("OMDWG"), which was established by the Commission approximately two years ago, has failed to achieve any meaningful progress for the retail electric markets. Further, given the posture taken by some of the participants in the OMDWG (including FirstEnergy), I am not encouraged that the OMDWG will yield any significant progress in the future either.

Q. Does Ohio law favor competition over monopoly regulation?

A. Yes. With the enactment of Senate Bill 2, the Ohio General Assembly chose to abandon the vertically integrated monopoly utility model and set Ohio down the path of electric competition. For the last 15 years, Ohio has moved down that path (albeit at times slowly) in no small part due to the efforts of the Commission. Ohio customers are just now starting to realize the benefits of competition and the Commission's efforts. Adoption of the Third Supplemental Stipulation would be a fundamental shift of the Commission's previous pro-competitive policies and decisions. Certainly there is still much work to be done for Ohio customers to realize the full benefits of retail competition, and this is why I continue to recommend additional retail market enhancements; however, adoption of the Third Supplemental Stipulation would subvert Ohio's pro-competitive policies, and the Commission's previous efforts to move competitive retail electric markets forward.

3. The Third Supplemental Stipulation Has a Number of Significant Add-Ons that Will Largely Benefit FirstEnergy Shareholders at the Expense of Customers

Q. Are many of the additional provisions in the Third Supplemental Stipulation reasonable?

A. No. Given the significant benefits that FirstEnergy shareholders would receive from approval of Rider RRS, one would expect that additional provisions in a Stipulation approving Rider RRS would not result in additional monetary benefits to FirstEnergy. However, that is not the case with the Third Supplemental Stipulation - there are a number of additional provisions in the Third Supplemental Stipulation that would make the ESP, as a package, *even more lucrative for FirstEnergy shareholders* than the ESP application as filed.

Q. Can you please discuss the *additional* provisions in the Third Supplemental Stipulation that will result in increased earnings for FirstEnergy shareholders, beyond what would be received from Rider RRS?

A. Yes. There are a number of additional provisions in the Stipulation that would result in *increased* earnings for FirstEnergy shareholders, in addition *to* Rider RRS. Those provisions include:

- Provision E(3)(c) of the Third Supplemental Stipulation which would increase the amount of "shared savings" FirstEnergy can earn from its energy efficiency programs from $10 million to $25 million. FirstEnergy's shared savings cap was set by the Commission in a previous energy efficiency plan case, and there is no apparent reason why Third Supplemental Stipulation should attempt to unilaterally give FirstEnergy shareholders $15 million *more* in earnings above what the Commission already approved in a previous case.
- Provision (G)(2) of the Third Supplemental Stipulation increases the amount FirstEnergy can recover through its delivery capital recovery rider ("Rider DCR") by over $100 million over the course of the ESP period. This provision simply allows FirstEnergy to earn more distribution revenue without having to come in for a distribution rate case to evaluate whether FirstEnergy's return on distribution investments is reasonable. Again, there is no apparent reason why FirstEnergy shareholders are being afforded this additional profit earning opportunity, given FirstEnergy shareholders would already be reaping the benefit of Rider RRS.
- Provision D(3) of the Stipulation would give FirstEnergy a 50 basis point adder on an already substantial 10.38% return on equity FirstEnergy would be able to earn in its grid modernization infrastructure deployment. It is not clear why the Third Amended Stipulation would just give FirstEnergy Shareholders an addition 50 basis points return on equity, above the Commission approved rate of return, which is already generous in this low interest rate environment.

Q. Can you discuss the provisions in the Third Supplemental Stipulation that insulate FirstEnergy from the risk of collecting distribution revenue at the expense of distributed generation development?

A. Yes. The Stipulation indicates that FirstEnergy will file a proposal to collect its distribution rates through a straight fixed variable ("SFV") rate design. Such a rate design would largely decouple the collection of FirstEnergy's distribution revenue requirement from the amount of kilowatt hours its customers use. This type of rate design reduces FirstEnergy's risk of recovering the revenue requirement and disincentives distributed generation and energy efficiency. However, even though FirstEnergy's risk is reduced, there is no corresponding reduction to FirstEnergy's rate of return which was approved based on the risk profile of FirstEnergy's current distribution rate design. Again, this provision in the Stipulation that allows FirstEnergy to maintain the same rate of return, while significantly reducing FirstEnergy's risk, is another give-away to FirstEnergy shareholders, on top of what is being received from Rider RRS.

Q. How does a SFV rate design provide a disincentive to distributed generation and energy efficiency?

A. An SFV rate design largely uses a customer charge to collect the distribution revenue requirement. In so doing, a customer that takes less electricity from the grid will pay the same amount for distribution service as a customer that uses significantly more electricity. Thus, customers that displace the electricity that they would otherwise take from the grid—as a result of either distributed generation or energy efficiency—are unfairly punished by a SFV rate design. As FirstEnergy noted in when the Commission opened a proceeding to evaluate the appropriateness of a distribution decoupling mechanism "[m]oving to a SFV design where customers are charged a fixed charge for distribution and a variable charge for generation diminishes the customer incentive needed to spur distribution efficiency and demand reductions from a customer perspective."[5]

Q. Should customers that reduce the amount of electricity they take from the grid be required to pay the same customer charge as other less efficient users of electricity?

A. No. When a customer reduces the amount of electricity that they take from the grid, they may reduce the need for expensive utility distribution infrastructure investment. This concept is the basis for establishing distribution level markets, such as in New York, broadly referred to as Reforming the Energy Vision ("REV").

Q. Are there other problems with the proposal to establish an SFV?

A. Yes. Normally such a drastic change in rate design would occur within the context of a distribution rate case and pursuant to a cost of service study. Indeed, FirstEnergy raised this very issue when the Commission opened a proceeding to evaluate the appropriateness of a distribution decoupling

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[5] *In the Matter of Aligning Electric Distribution Utility Rate Structure With Ohio's Public Policies to Promote Competition, Energy Efficiency, and Distributed Generation*, Case No. 10-3126, Comments of FirstEnergy at 11 (Feb. 11, 2011)(see Exhibit MW-1).

mechanism: "The Companies also recommend that any efforts to implement a straight fixed variable approach for electric utilities not move forward until the electric utility's filing of its next base distribution rate case."[6]

Q. Does the Third Supplemental Stipulation contain any additional inappropriate subsidies of generation-related resources?

A. Yes. The Stipulation proposes that FirstEnergy has the authority to develop battery resources and recover the cost of such investment through rate base. Batteries are distributed generation resources that can be used to sell energy, capacity, demand response, and ancillary services (frequency regulation) into the wholesale market. Moreover, batteries can be used in conjunction with renewable energy (such as solar and wind) to enhance the value of these resources. Because batteries relate to generation service, it would run afoul of state policy to recover the cost of these resources through distribution rates. Finally, given that CRES providers such as IGS have already invested in these resources without the guarantee of a regulated return, it would be unfair, unjust, and unreasonable to allow FirstEnergy to place the risk of its investment on the backs of distribution customers.

Q. As a whole is approval of the Third Supplemental Stipulation more lucrative for FirstEnergy than just approving the ESP Application as filed?

A. Yes. Many of the additional provisions in the Third Amended Stipulation actually made the ESP more lucrative for FirstEnergy. One would think if FirstEnergy

[6] *Id.* at 1.

shareholders were to receive such a great benefit as Rider RRS, the Commission would not want to then give FirstEnergy shareholders even more monetary benefit. For this reason, the Commission should not approve the Third Supplemental Stipulation.

III. CONCLUSION

Q. Can you please summarize your testimony and recommendations?

A. Yes. As I explained in my previous testimony filed in this proceeding, FirstEnergy's ESP Application as filed is unreasonable and should be rejected unless substantial modifications are made to the application that would enhance the retail electric market. However, the Third Supplemental Stipulation does not improve FirstEnergy's ESP Application – it makes it worse. The Third Amended Stipulation contains no retail market enhancements such as those I described in my direct testimony; rather the Third Supplemental Stipulation contains provisions that would actually be even more harmful for Ohio's retail electric markets. Moreover, natural gas trends over the last year have made the economics of FirstEnergy's proposed Rider RRS even more unattractive for customers. For these reasons, I recommend that the Commission reject the Third Supplemental Stipulation. At a minimum, if the Commission is inclined to adopt the provisions in the Third Supplemental Stipulation, the Commission should also adopt provisions I recommend in my direct testimony including:

- Unbundling SSO costs recovered through distribution rates, and charge those costs to SSO customers directly;

- Allowing non-discriminatory access for CRES suppliers to bill for non-commodity charges on the utility bill;
- Start a process that ultimately moves to a supplier consolidated billing model.

Q. Does this conclude you supplemental testimony?

A. Yes, it does.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing *Second Supplemental Testimony of Matthew White* was served this the 30th day of December 2015 via electronic mail upon the following:

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FILE

Ex. MW-1 14

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of Aligning Electric Distribution Utility Rate Structure With Ohio's Public Policies to Promote Competition, Energy Efficiency, and Distributed Generation	)))))	Case No. 10-3126-EL-UNC

COMMENTS OF OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND THE TOLEDO EDISON COMPANY

Come now Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company ("Companies"), by counsel, and respectfully submit their comments in response to the Public Utilities Commission of Ohio ("Commission") Entry, dated December 29, 2010, which required that comments be submitted by February 11, 2011.

The Companies appreciate the opportunity to provide comments to the Commission as it begins its consideration of whether modifications to distribution rate structures for regulated electric utilities in Ohio would better align utility performance with Ohio's desired public policy outcomes; and if so, what modifications should be adopted. The Companies understand that this proceeding is just the first step in the process and that further proceedings and opportunities for input will be provided before the PUCO makes any specific decision to move forward with decoupling.[1] The Companies also recommend that any efforts to implement a straight fixed variable approach for electric utilities not move forward until the electric utility's filing of its next base distribution rate case. The Companies believe that the current distribution rate structure in Ohio, which provides for the recovery of lost distribution revenues, is best aligned

[1] Simply because an issue or comment is not specifically raised regarding a particular item does not constitute a waiver of the Companies' ability to raise the issue at a later date. The Companies reserve the right to modify their comments and to address any and all issues raised with regard to the implementation of decoupling.

with Ohio's public policy desires and customer interests. To adopt any unproven modifications in the hopes of better alignment may result in unintended consequences contrary to sound public policy and may well create an unnecessary administrative burden associated with frequent rate proceedings. Absent a showing that the current distribution rate structure is contrary to Ohio public policy, the Companies believe it is premature to consider modifications. The Companies comments are structured with general comments immediately set forth below and responses to the questions posed in their Entry following the general comments.

I. General Comments

In its Entry, the Commission identified at least three separate forms that it has characterized as potentially falling under the "decoupling" banner, including a straight fixed variable approach, periodic rate modifications, and lost revenue recovery. The Entry then goes to suggest that combinations of these three may also be considered by the Commission. The Companies believe that attempting to recover all fixed distribution costs through a single customer charge applied to all customers, i.e., straight fixed variable ("SFV"), ignores the cost causation principle of ratemaking and may have the effect of shifting cost recovery from higher-usage customers to lower-usage customers. As described in the Entry, both the SFV design and the Decoupling adjustment design would fix distribution revenues while ignoring changing distribution system costs. The Companies believe that the traditional distribution base rate cases together with lost distribution revenue recovery for energy efficiency related reductions in sales is an appropriate middle ground between a SFV/rate modification approach and traditional rate cases with kWh distribution charges, and best supports the public policy desires of Ohio. This approach, coupled with distribution rates designed based on a customer's demand, significantly reduces the throughput incentive, keeps intact the cost causation principle and simultaneously maintains customer incentives to support energy efficiency efforts.

Recognizing this, during the Companies' last distribution rate case the Companies altered the distribution rate design to incorporate charges based on billing demands and customer charges wherever possible. *See* Case No. 07-551-EL-AIR. The Companies' nonresidential distribution rates, General Service-Secondary (Rate GS), General Service-Primary (Rate GP), General Service Sub-Transmission (Rate GSU) and General Service-Transmission (Rate GT) now contain only demand-related charges and a customer charge.

The only distribution rate that is not structured based upon a demand charge is the residential tariff simply because the installed metering does not capture the billing determinants necessary to charge based on demand. The cost to install the metering necessary to measure demand for the residential rate schedule is prohibitive. Instead of a demand based rate, residential customers' distribution rate consists of a fixed component, or service charge, and a kWh energy charge. For residential customers, this is a reasonable rate design because of the correlation between energy consumption and demand, i.e., the energy charge serves as a reasonable proxy for the residential customers' distribution demand. Based upon the support of most parties to the Companies' distribution case, the Commission approved the rate design in its Order in that case. With those changes in place, the Companies then sought and were granted recovery of lost revenues for energy efficiency and peak demand reduction programs through the Commission's adoption of the Stipulation in the Companies' first and second ESP proceedings, Case Nos. 08-935-EL-SSO and 10-388-EL-SSO respectively. The Companies believe this structure addresses the concerns expressed in the Entry regarding the "throughput incentive", fundamentally preserves the existing distribution rate design and supports energy efficiency and peak demand reduction efforts.

A. Distribution Tariff Design and Changing Cost to Serve

Distribution rates resulting from a distribution base rate case represent a snap shot in time of what customers should be charged for distribution service based upon the evidence that was presented during the proceeding. The many variables that make up the cost of providing distribution service begin to change even before an order is issued in a case. For example, rate base changes, operation and maintenance costs change, sales volumes change, customer counts change, weather changes, the economy changes and end-use saturation rates change. Given those changes, while rates may remain reasonable, they will never universally reflect precise cost recovery over the period the rates are in effect. The historic balance that has been struck, and remains in place today, is that if the rates do not provide sufficient revenues to provide adequate service and a reasonable return, then an electric utility may file a request with the Commission to increase rates. Conversely, the Commission tests utility earnings on an annual basis to determine if the current rates are providing a significantly excessive return, and if so, has mechanisms at its disposal to address the situation.

Both the SFV and the Decoupling Adjustment approaches discussed in the Entry address only one of the components that make up the rates of an electric utility, i.e., revenue. The premise appears to be that an electric utility should not be permitted to collect more than its authorized revenue and that these approaches would be applied to ensure that they did not. But authorized revenue is not the determinant or driving force behind setting rates. As recognized in the Entry, the definition of decoupling for gas companies is a mechanism "that provides recovery of fixed costs of service and a fair and reasonable rate of return, irrespective of system throughput or volumetric sales." Entry at 3. Consistent with this definition, an electric utility is permitted to recover its prudently incurred costs together with an opportunity to earn a fair and reasonable return on its investment. Thus, it is the combination of costs plus a return that are the critical components of utility rate setting. The authorized revenue is simply the end result of a mathematical formula, and forms the basis for the development of the rates to be charged to customers.

By providing an adjustment mechanism to ensure that only the "authorized" revenue amount from a previous rate case is permitted to be collected, changes in costs necessary to provide safe reliable service to customers are ignored. If either SFV or the Decoupling Adjustment were implemented in an increasing cost environment, then the logical outcome of resetting revenue collected to the amount needed to recover an historic and no longer accurate level of costs would be almost continuous base distribution rate cases being filed. This sort of regulatory churn is costly both in terms of economic and human resources, and is unnecessary. Rate cases should only be filed when the electric utility's rates do not permit it to earn a reasonable return. SFV or a Decoupling Adjustment should not be used to carve out one element of the ratemaking formula to the detriment of customers, the Commission, the Companies, and other interested stakeholders.

The Companies, and presumably the other electric utilities in the state, are in a rising cost environment - the cost of constructing and maintaining the distribution system continues to rise. For instance, in the past seven years the Companies have witnessed the following cost increases in the basic material it uses:

-Line Transformers 177%
-Underground cable 82%
-Overhead wire 129%
-Power transformers 109%

-Conduit 41%
-Line Trucks 51%
-Treated wood poles 35%

The risk faced by the Companies would also increase as the result of the implementation of the either the SFV or Decoupling Adjustment approach to decoupling. Effectively having a rate case every year, or possibly even more often, could increase the regulatory risk and uncertainty for investors and will also substantially increase rate case expense, the cost of prosecuting rate cases, on the part of the Companies, interested stakeholders, and the Commission itself. And it is not needed. Under the current structure, Companies file rate cases only when needed to adjust rates to permit them the opportunity to earn a reasonable return – which provides a level of stability to the rates and an amount of certainty for customers and the Companies.

B. Other Expected Impacts of SFV

One impact on customers of a decoupling mechanism would be price signals that undermine that value of conservation and peak demand reduction for customers, which may cause customer confusion and conflict with the state policy initiative of increasing energy efficiency and reducing peak demands. Further, the Rider USF charge, which is the Rider that recovers PIPP program arrearages, may well increase as the shift to SFV causes both the level of arrearages from current PIPP customers to rise as well as the number of PIPP customers to rise.

First, with a shift to SFV, the kWh or kW charge for distribution service will be reduced or eliminated. A byproduct of this change in distribution system rate design will be to reduce the savings that customers experience either through energy efficiency and/or peak demand reduction efforts. Customers will have less of an economic incentive to participate in energy efficiency or peak demand reduction programs resulting in an increase in the cost of the programs in order to achieve the statutorily required savings and reductions. This comes about because the customer is expecting that as they conserve energy or reduce their peak demand there will be a reduction in their distribution bill. If this doesn't happen, the economic incentive to reduce usage is reduced. By changing the price signals, the SFV rate design promotes the opposite outcome of the policy intent set forth in SB221 by reducing the benefit to customers who take the necessary steps to conserve energy. Such an approach seems antithetical to the requirements of R.C. 4928.64 and R.C. 4928.66. If the SFV approach with a revenue adjustment were implemented, customers will have to be given greater incentives to participate in order to achieve the Energy Efficiency and Peak Demand Reductions required by statute. This will cause higher amounts to be recovered through Rider DSE, which are paid for by all customers. Diminishing the value of energy efficiency and peak demand reduction for customers may also be seen as inconsistent with R.C. 4928.02, particularly divisions (D) and (M) that encourage the use of demand side management and energy efficiency programs.

A second consequence of a SFV decoupling mechanism is the unanticipated harm that could arise from going to a design that includes a much higher customer charge. This will negatively impact low use customers the most. The shifting of cost recovery may also be seen as inconsistent with R.C. 4928.02(L), which is the policy statement to protect at-risk populations. To the extent these low use customers are also low income customers and these low use customers are already participants in the PIPP program, shifting revenue responsibility will not increase their obligation to pay, but will simply shift more dollars into the USF rider that all customers pay. Further, substantially increasing the cost for low income customers that qualify for PIPP, but that do not currently participate in the PIPP program may well drive substantially more customers to join the PIPP program, thereby increasing the USF Rider even more and further shifting the burden to other customers.

C. Companies' Approach

As noted above, the Companies acknowledge the Commission's concern with the recovery distribution system costs through purely kWh charges. The Companies in their last distribution rate case, in large part, converted kWh or usage based charges into kW or demand based charges for the non-residential schedules. This approach addresses the basic "throughput incentive" concern expressed by the Commission in the Entry.

The Companies have also recognized the special circumstance arising from the requirement to achieve energy efficiency and peak demand reduction benchmarks set out in SB221. The Companies view this as an isolated circumstance that should be addressed through the recovery of lost revenues without specifically impacting overall distribution rate design. The Companies believe the Commission should provide a mechanism where the recovery of costs associated with energy efficiency and conservation programs, including lost distribution revenues, can be approved in a timely manner so that customers may take advantage of new opportunities to conserve energy.

The existing distribution rate design is based on decades of cost of service studies and related distribution rate design both of which are based on well-established rate making principles that have been tested in countless proceedings. Nothing has changed to alter the underlying basis for that body of work or the resultant rate design. To toss out what we have without any showing that it is improper or counter to public policy is inappropriate. For example, with regard to cost causation and recovery of distribution system costs from those customers causing the cost, the SFV approach suffers from many limitations. Principally, the costs are not being recovered from the cost causers. Without metering to measure the demand of residential customers, the precise cost of the distribution system cannot be allocated on a pure cost basis. Simply dividing total fixed costs by the number of customers to result in a fixed monthly charge does not recognize that higher level users are causing higher than average costs on the distribution system. Adopting the SFV approach may simply flip the presumed existing higher-use customer subsidy of lower-use customers to just the opposite, i.e., lower-use customers subsidizing higher-use customers. With the Companies' current structure, as a customer's demand increases (or usage in the case of a residential customer) the more distribution costs are recovered from that customer. This is appropriate since they are causing the higher costs to be incurred on the system.

The Companies further believe before any modification to the existing rate design is considered, much less implemented by the Commission, customer attitudes must be tested to determine the receptivity to modifications to rate design. Experience demonstrates that customers are sensitive to changes in the billing for their electricity consumption. Even rate design changes that are revenue neutral within a class can create a customer reaction that overwhelms any positive intent of the change.

In conclusion, if current distribution rate design is changed such that reducing consumption or demand no longer provides any savings to customers, then the simple message to customers of: "If you use less, you can save money on your bill" will be lost for distribution related charges.

II. Responses to Questions Posed in the Entry

1. Are there fundamental operational distinctions between natural gas & electric utilities that must be considered in determining whether and how to eliminate or mitigate the throughput incentive in electric distribution rates?

There are attributes unique to the electric distribution businesses that influence distribution rate design that should be considered when considering modifications to the distribution rate design.

a. The electric distribution system is designed to accommodate individual customer and class peak demands that are driven by instantaneous loads. The utility has to install and maintain sufficient distribution capacity to meet customers' peak demands even as these load centers shift and migrate with customers.

b. To the extent that customers' individual demands continue to grow, additional plant capacity is needed regardless of the changes, if any, in the number of customers on the system

c. Unlike natural gas, consumption of electricity and the number of electric utility customers continue to grow driving the need for investment in the distribution system. For the period 2002 – 2009 average residential electric consumption grew 1%. This growth has occurred even during a period of recession. During this same time period, average residential natural gas consumption fell by 12%. Decoupling may make sense in a declining sales industry, like natural gas, but it is wholly inappropriate in the electric industry where sales and costs are increasing.

d. Although kWh usage or throughput may not directly cause the costs that drive capital investment in the distribution system for the residential class, a correlation between kW demand and kWh usage has been exhibited. Simply put, customers who use more electricity have higher demand for electricity and require more distribution infrastructure to serve.

e. Increasing mandates and policy support for distributed generation, net metering, new reliability standards, smart grid, and renewable resources create new operational challenges on the distribution system that must be addressed and will likely give rise to the need for additional distribution investment. These requirements are unrelated to the costs of the existing distribution system, the volume of kWh sales or the number of customers on the system. But these new requirements must be recognized in any distribution rate design going forward.

2. Are there factual or policy considerations that suggest electric distribution rate design should be constructed differently from natural gas?

Yes. First, electricity usage on average for residential customers is trending upward whereas residential natural gas usage is trending downward. Second, electric utilities have statutorily mandated energy efficiency and peak demand reduction benchmarks. Third, gas companies do not have a state policy consideration to protect at risk populations. Fourth, the electric utilities are required to meet Commission mandated minimum reliability standards. Fifth, annual gas usage patterns vary significantly from that of electricity usage. As a result of the foregoing, the Companies favor a distribution rate design that:

a. Recognizes electric distribution rate design should be based on its unique operational attributes. Costs are caused by building the system to meet individual customers' and class peak demand

b. Includes tariffs designed to spur efficiency from a utility and customer perspective.

c. Fully compensates utility participation in approved energy efficiency and peak demand reduction programs through timely recovery of ongoing costs on a standalone basis, including fair return on invested capital, and recovery of lost revenues.

d. Enables utility customers to effectively use the utility service while understanding the drivers of their costs to use the service

3. If the Commission adopts a decoupling rate design, which design should it use: SFV, decoupling adjustment, lost revenue recovery adjustment, or a combination?

The Commission should continue with distribution rate design that is based on a customer's peak demand where practicable and based on kWh usage otherwise, coupled with a lost distribution revenue recovery mechanism. The lost revenue recovery adjustment meets the goals of SB221 by encouraging the utility to support energy efficiency and peak demand reduction while allowing for investment where necessary to continue providing adequate service in an environment of usage, demand, and customer growth.

Moving to a SFV design where customers are charged a fixed charge for distribution and a variable charge for generation diminishes the customer incentive needed to spur distribution efficiency and demand reductions from a customer perspective. It will result in a shifting of costs from higher-usage customers to lower-usage customers, without assurance that the new distribution rate design more properly assigns costs to cost causers. Again, this quick fix to a problem that no one has demonstrated exists throws out decades worth of studies designed to identify the distribution cost causers. Additionally, the SFV rate design makes adjustments only to revenue levels while ignoring an electric utility's ability to recover its prudently incurred costs, particularly increasing costs associated with materials cost increases and an opportunity to earn a reasonable return on investment.

4. If the Commission adopts a decoupling rate design in electric distribution rates:
a. Should it only be applied to residential classes? What other classes?

As one element of an overall rate design, lost distribution revenue should be recovered from all customer classes other than GT.

b. How often should the Commission require a utility to update?

The current framework, which allows utilities to determine when they need to seek a change to distribution rates, is appropriate and provides balance and stability to customers and the electric utility while also providing appropriate flexibility. In addition, the Companies believe that the current method of collecting lost distribution revenues through the Company's Rider DSE, Demand Side Management and Energy Efficiency Rider, is the most appropriate.

The Commission has the opportunity to review the lost revenue recovery at least semi-annually when the rider updates are submitted for review and approval.

c. Should rate of return be adjusted to reflect reduced risk?

No, a utility's rate of return is a function of a myriad of issues and adjusting the rate of return because a lost revenue recovery mechanism exists smacks of single issue rate making and overlooks the fact that investing in energy efficiency and peak demand reduction measures along with distributed generation and renewable resources actually increases the risks associated with operating a distribution utility. Further, if the SFV design is implemented as described in the Entry, then the risk of the electric utility would actually increase. Fixing revenues does not equate to fixing earnings. As previously stated distribution expenses rise between rate cases so fixing revenue may actually increase the variability of earnings. This business risk is what drives a company's cost of capital because investors must bear it. Fixing revenues may actually increase the business risk for the utility and therefore investors' required return. In many cases where rate of returns have been modified in other states, they have been adjusted on an arbitrary basis based on the perception of lower risk rather than an actual study of the business risk.

5. If the Commission adopts some element of a decoupling rate design:

a. Should adjustments be made on total revenue, per customer revenue or some other basis?

A lost revenue recovery approach would not require separate adjustments to total revenue or per customer revenue. Other decoupling rate designs would need to be adjusted for inflation, weather, economic growth, growth in numbers of customers and growth in peak demand because many of these actually increase distribution costs for the company.

b. Should adjustments be normalized for weather?

See the response to (a).

c. Should the Commission adopt any special features to shield consumers from volatile adjustments (e.g. caps, collars, bands?)

No, such special features should not be needed if the Commission implements a rate structure that avoids the occurrence of the necessity for "volatile adjustments." If the Commission fails to do so, then it should adopt mitigation features and the Company should be allowed to defer adjustments with full carrying charges including cost of equity.

6. If the Commission determines that a decoupling rate design should be implemented to eliminate or mitigate the throughput incentive in electric distribution rates:

a. When should this change occur (i.e. in what types of actions before the Commission should this change be implemented?)

The Commission should strive to support rate design that is based on cost causation. As stated above, the Commission should not consider a SFV rate design for residential customers until costs can be properly assigned. When the information is available to support an allocation of fixed costs to customers is when the Commission should consider such action. Also, the timing of any efforts to change rate design needs to respect the many important aspects of current ESPs approved by the Commission and to not disturb the careful balance struck in those plans by changing distribution rate design prior to their expiration. The Companies recommend that any efforts to implement a straight fixed variable approach for electric utilities not move forward until the electric utility's filing of its next base distribution rate case.

b. *Should it be phased in?*

To the extent that any rate design causes shifts the allocation of costs from one set of customers to another, particularly when the rates are designed without regard to cost causation and result in significant increases in costs to certain customers and significant decreases in costs to other customers, the rates should be phased in.

c. *Over what period of time?*

It would depend how much customers are harmed and this would vary by operating company and the rate design chosen. For example on average across the Companies' service territories, under a fixed charge scenario a customer who uses an average of 400 kWh per month would see their bills for distribution go from $21/month to roughly $27/month or $252/year to $325/year. Smaller customers such as these would experience large percentage increases if rates were not phased in.

7. *In order to review the various decoupling rate designs, the Commission will need necessary data such as that included in Appendix B. Is the data contained in Appendix B:*

a. *Burdensome*
b. *Appropriate*
c. *Comprehensive*
d. *Proprietary*

In order to provide the types of information described in Appendix B, the Companies would need to conduct special studies which would be time-consuming and burdensome. The information described on Appendix B is not comprehensive however. The appendix is looking at one year's worth of information – the Companies believe that there should be the option to look at more than one year. The year 2010, for example, was impacted by both the economy and the extreme summer weather, which if viewed in isolation could lead to inaccurate conclusions.

In addition, using average bills and figuring out how many bills are above and below those levels ignores the types of customers being impacted. In making any decision on a rate design methodology that would re-allocate recovery of costs among types of residential customers, more information needs to be considered than is being requested in Appendix B. In addition, the consideration of what customers or customer groups are causing the distribution costs needs to be part of any discussion of changing rate designs. The Commission should put off discussions about changing rate design until more information is available regarding individual contributions toward peak demand by different types of residential customers.

While the nature of the information described below, to a large degree, would not necessarily be considered proprietary at the preliminary juncture, the Companies reserve all of their rights to protect the confidentiality of any information that may be subsequently required to be produced.

III. Conclusion

The Companies appreciate the opportunity to provide comments related to the Commission's consideration of the issue of decoupling, and urge the Commission to move with great caution when considering modifications to the existing distribution rate design. We look forward to providing additional input should the occasion present itself in the future.

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Respectfully submitted,

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