STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, establishing the method and avoided cost calculation for **CONSUMERS ENERGY COMPANY** to fully comply with the Public Utility Regulatory Policies Act of 1978, 16 USC 2601 *et seq*.	)	Case No. U-18090

At the November 21, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

OPINION AND ORDER

History of Proceedings

The Commission opened this contested case proceeding in an order issued on May 3, 2016 (May 3 order), directing Consumers Energy Company (Consumers) to file proposed avoided cost calculation methods and costs in accordance with the requirements of the Public Utility Regulatory Policies Act of 1978, PL 95–617; 92 Stat 3117 (PURPA).

Under PURPA, the Commission is required to establish accurate and up-to-date avoided capacity and energy costs for each rate-regulated utility. Electric utilities are not required to pay "more than the avoided costs" for purchases from qualifying facilities (QFs), and, avoided cost is defined as "the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate or purchase from another source." 18 CFR 292.304(a)(2) and 18 CFR 292.101(b)(6).

The Commission has considerable discretion in deciding which avoided cost method is most appropriate, and it must consider a number of criteria as set forth in 18 CFR 292.304(e), including the utility's plans to add capacity, the availability and reliability of output from the QF, and the incremental capacity available from QFs that may delay or limit the addition of large amounts of capacity by the utility. Ultimately, the Commission must arrive at avoided cost rates that are "just and reasonable to the electric consumer of the electric utility and in the public interest;" and that do not "discriminate against qualifying cogeneration and small power production facilities." 18 CFR 292.304(a)(1)(i) and (ii).

In its initial filing, Consumers was instructed to provide avoided cost calculations using: (1) the hybrid-proxy plant method proposed in the PURPA Report;[1] (2) the transfer price method developed under 2008 PA 295 (Act 295); and (3) another method, if any, that the company wished to propose. Consumers was also directed to file a proposed Standard Offer tariff, including applicable design capacity.

Pursuant to the May 3 order, Consumers filed various avoided cost methods and costs on June 17, 2016. Administrative Law Judge Mark E. Cummins (ALJ) held a prehearing conference on July 21, 2016. At the prehearing conference, the ALJ granted petitions to intervene filed by, among others, Independent Power Producers Coalition of Michigan (IPPC); Great Lakes Renewable Energy Association (GLREA); and Environmental Law & Policy Center, Ecology

[1] In an order issued on October 27, 2015, in Case No. U-17973, the Commission opened an investigation into issues concerning PURPA avoided costs. After a series of meetings and a round of comments, the investigation culminated on April 8, 2016, when the Commission Staff (Staff) filed a final report (PURPA Report).

Center, Solar Energy Industries Association, and Vote Solar (collectively, ELPC). The Staff also participated in the proceedings.

On May 31, 2017, the Commission issued an order (May 31 order) finding: (1) the most appropriate method for determining Consumers' avoided capacity and energy costs is the Staff's hybrid-proxy method, which is based on the avoided capacity cost of a natural gas combustion turbine (NGCT) and the avoided energy cost of a natural gas combined cycle (NGCC) unit; (2) zonal resource credits (ZRCs) should be applied to intermittent resources like wind and solar; (3) a fixed investment cost attributable to energy (ICE) should be added to the energy portion of avoided costs; (4) a 10-year planning horizon is reasonable for determining whether Consumers requires additional capacity, and if the company requires any capacity during the planning period, it should pay QFs for both capacity and energy; (5) expiring contracts for existing QFs should be renewed at the full avoided cost rate, whether or not Consumers forecasts a capacity shortfall; (6) if no capacity is needed during the 10-year planning horizon, then Consumers shall make a filing so indicating, and, going forward, the avoided cost for capacity shall be reset to the Midcontinent Independent System Operator, Inc.'s (MISO's) planning reserve auction (PRA) price; (7) the design capacity for the Standard Offer should be set at two megawatts (MW); (8) Standard Offer term lengths should be set at five, 10, 15, and 20 years at the option of the QF; (9) except for line losses, there was insufficient evidence in this record to quantify other avoided costs including reduced transmission costs, reduced air emissions and environmental compliance costs, and the hedging value resulting from QF power. However, this issue should be revisited in the company's next avoided cost review; (10) a line-loss credit of 2.37% should be applied to the energy portion of the Standard Offer, until more information is available, and the credit should be negotiated for other agreements; (11) renewable energy credits belong to the QF under both the

Standard Offer and negotiated power purchase agreements (PPAs); (12) the next review of Consumers' avoided costs should be conducted in two years; and (13) additional PURPA issues, including rates for stand-by service, back up, and supplementary power are being addressed in other proceedings. The Commission further determined that the record should be reopened for the taking of additional evidence on the appropriate inputs for the hybrid proxy model.

In accordance with the May 31 order, on June 12, 2017, Consumers, the Staff, ELPC, and IPPC filed testimony and exhibits for the reopened proceeding. Between June 19 and June 26, 2017, the parties filed corrected testimony and exhibits or rebuttal testimony and exhibits. Evidentiary hearings were conducted on June 21 and June 27, 2017.

In a second order issued on July 31, 2017 (July 31 order), the Commission: (1) approved inputs to the NGCT model;[2] (2) upon further consideration, found that the MISO ZRC capacity structure should apply to all QF resources, not only solar and wind; (3) found that run-of-the-river hydro <u>only</u> may opt for a levelized energy payment in lieu of an escalating payment; and (4) determined an appropriate heat rate and assumed capacity factor for the NGCC proxy unit.[3] However, the Commission also found that:

> [T]he reopened record lacks some of the required information to develop . . . a schedule [of escalating energy payments]. Therefore, the Commission again remands this case for the development of a final energy avoided cost schedule, based on the determinations made in this order, coupled with the schedule of nominal gas prices for 2017 from [Energy Information Administration] EIA. As it has discussed previously, the Commission has a preference for publicly available information, which is consistent with EIA information.

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[2] For the avoided cost of the NGCT proxy plant, the Commission approved the Staff's inputs contained in Exhibit S-11, with the company's amount for fixed operations and maintenance (O&M) costs as shown in Exhibit A-15.

[3] The Commission approved a heat rate of 6.600 million British thermal units per megawatt-hour (MMBtu/MWh) and a capacity factor of 61.77%.

July 31 order, p. 31.

On August 11, 2017, IPPC filed a petition for rehearing of the July 31 order. On September 1, 2017, Consumers filed a response to the petition. In accordance with the schedule set forth in the order, the parties timely filed their direct and rebuttal cases. A hearing was conducted on August 30, 2017.[4] Pursuant to agreement of the parties, there was a single round of briefing, with briefs filed on September 14, 2017. The record in this reopened part of the proceeding consists of 145 pages of transcript and 29 exhibits admitted into evidence.

Review of the Record

Natalie N. Busack, Senior Rate Analyst II in Consumers' Rates and Regulatory Affairs Department, provided an updated Standard Offer tariff that she testified was consistent with the company's calculations and the July 31 order. Ms. Busack explained that the tariff was modified to include updated energy and capacity prices along with language concerning the timeline for contract processing. 3 Tr 210-211, Exhibit A-34.

Jim K. Chilson II, Fuels Transportation & Planning Director in Consumers' Energy Supply Operations Department, testified regarding Consumers' proposed avoided cost inputs for the price of natural gas. According to Mr. Chilson, the Commission should adopt the company's Henry Hub natural gas price nominal forecast, set forth in Exhibit A-36, because this forecast most accurately represents how Consumers projects natural gas prices. Mr. Chilson explained that Consumers develops a composite forecast from a number of industry sources and experts thereby reducing the risk that any one projection is inaccurate. 3 Tr 218. Mr. Chilson disagreed with the

[4] At the evidentiary hearing, the ALJ granted Consumers' motion to file surrebuttal testimony and denied the company's motion to strike certain parts of IPPC's witness' rebuttal testimony.

use of the EIA forecast for projecting natural gas prices, noting that EIA forecasts are generally higher than actual transactions, citing Exhibit A-38, which shows EIA forecasts for 2014-2016.

Mr. Chilson testified that, in addition to the cost of gas at the Henry Hub, transportation costs to move the gas to Consumers' City Gate must be included. According to Mr. Chilson, this cost recently has been approximately $0.08/MMBtu. Mr. Chilson further testified that Consumers calculated a charge to transport gas from the City Gate to the proxy unit based on an estimated XXLT rate (based on a DTE Gas Company (DTE Gas) tariff) for its proposed Thetford plant location. According to Mr. Chilson, this cost would amount to an annual charge of $3.5 million and a variable charge of approximately $0.23/MMBtu. 3 Tr 220, Exhibit A-35.

Priya D. Thyagarajan, a General Engineer in Consumers' Energy Supply Operations Department, testified regarding Consumers' updated inputs to the NGCT and NGCC proxy units, along with ICE, and a proposed schedule of energy payments. 3 Tr 240-242; Confidential Exhibit A-40 and Exhibit A-41. Ms. Thyagarajan recommended that the Commission adopt Consumers' proposed variable costs for an advanced NGCC because these costs best represent the company's avoided unit.

Julie K. Baldwin, Manager of the Renewable Energy Section of the Commission's Electric Reliability Division, presented the Staff's recommended Standard Offer tariff. Ms. Baldwin stated that the tariff had been updated to include or clarify certain language, as directed by the July 31 order. 3 Tr 268-269, Exhibit S-17.

Kenneth G. Troyer, Supervisor of the Contract Strategies group in the Supply Operations Department at Consumers, filed rebuttal to Ms. Baldwin, stating that his main concern with the Staff's Standard Offer (Exhibit S-17) was the locational marginal price (LMP) forecast rate option where the Staff appeared to have double-counted ICE and line losses. Mr. Troyer added that

Consumers intends to update the levelized on-peak and off-peak LMP prices in its Standard Offer tariff following the final order. 3 Tr 257.

Jesse J. Harlow, a public utilities engineer in the Renewable Energy Section of the Commission's Electric Reliability Division, provided the Staff's forecasted natural gas prices, including an energy payment on both a levelized basis and as a schedule.

Mr. Harlow explained that, pursuant to the July 31 order, he updated Exhibit S-14 to use the company's levelized fixed O&M expense for an NGCT and Consumers' data on forced outage and summer derate to calculate the ZRC capacity for the proxy NGCT. In Exhibit S-15, Mr. Harlow testified that he updated the heat rate for an NGCC to 6.600 MMBtu/MWh, included a gas transportation cost based on the company's information, and updated the ICE payment. 3 Tr 277-278.

Mr. Harlow testified that, with respect to the natural gas price forecast, the Staff continues to support the EIA 2017 Annual Energy Outlook for the Henry Hub. Accordingly, Exhibit S-15 uses the 2017 EIA real natural gas forecast with an inflation rate applied, and Exhibit S-16 uses the 2017 EIA nominal gas forecast. Mr. Harlow further explained that the Staff was offering a simplified method for calculating and reporting the energy component of avoided cost, which would combine a nominal natural gas forecast, gas transportation, and variable O&M to arrive at a transparent calculation of energy cost each year. Mr. Harlow indicated that reporting energy prices in the manner he suggests would resolve the debate over the use of real versus nominal dollars in the energy forecast. 3 Tr 279-280, Exhibit S-17.

In his response to Consumers, Mr. Harlow indicated that he did not dispute the company's inputs to the capacity calculation for fixed O&M costs; however, Mr. Harlow disagreed, in part, with Consumers' alternative gas forecast proposal. Mr. Harlow opined that while there may be some value in combining forecasts to mitigate the possibility that one forecast is incorrect, he disagreed that the average of several forecasts should be used to project a rate of change to years beyond five-year futures contracts. Mr. Harlow pointed out, "For each year beyond the five-year futures, the gas price forecast is lower than the EIA forecasts, since the Company is only applying the average change rate of the EIA forecasts and not the actual average gas price. This results in much lower gas prices in every year beyond the five-year futures when using Consumers' method." 3 Tr 283.

In rebuttal, Ms. Thyagarajan claimed that the NGCT variable costs of $110,903/MW-year or $129,336/ZRC-year, shown in Exhibit S-14, are inconsistent with the company's calculation of $117,203/MW-year ($140,505/ZRC-year). According to Ms. Thyagarajan, the difference appears to have resulted from: (1) the Staff's input for fixed O&M; (2) the Staff's exclusion of fixed gas transportation expense from its calculation; and (3) the Staff's use of a different conversion factor to compute ZRCs/MW.

Douglas B. Jester, a partner of 5 Lakes Energy LLC, testified on behalf of ELPC in response to the July 31 order. Mr. Jester indicated that he agrees with the Commission's preference for publicly available information, particularly the forecasts available from the EIA. Accordingly, Mr. Jester testified that he supports the EIA's 2017 forecasted delivered natural gas prices for the East North Central Region, which includes Michigan. Mr. Jester explained that Michigan utilities do not receive all of their gas from the Henry Hub, and the EIA regional delivered price takes into account transportation from various sources of supply. Mr. Jester opined that adopting his recommendation would simplify the calculation and reduce the number of potential errors that could result from making separate calculations for fuel and transportation cost. 3 Tr 288-289, Exhibit ELP-16.

Mr. Jester testified that, in accordance with the Commission's decision to adopt a heat rate of 6.600 MMBtu/MWh and its preference for the Staff's estimate of plant costs, he made an annual inflation adjustment to the ICE amount using Global Insight. Mr. Jester noted that the July 31 order did not specify a value for variable O&M expense for the NGCC proxy unit. Nevertheless, because the Commission largely adopted the Staff's analysis based on EIA information, ELPC used EIA's Capital Cost Estimate for Utility Scale Electric Generating Plant to arrive at a variable O&M expense amount of $3.50/MWh, which was then adjusted annually for inflation. Mr. Jester explained that he made an additional adjustment for avoided transmission line losses. *See*, Exhibit ELP-17. Finally, Mr. Jester recommended that the following language be added to the Standard Offer tariff to clarify the interplay between avoided capacity cost and MISO ZRCs:

> Capacity value for intermittent resources is based on MISO zonal resource credits (ZRCs). Capacity value paid to QFs does not depend on whether the Company actually obtains ZRCs for such capacity, only that the Company could obtain ZRCs for the QF capacity. Capacity value paid to a QF is in units of $/ZRC. MISO ZRCs are equal to the projects [sic] nameplate capacity (in MW AC) modified by the MISO effective load carrying capacity (ELCC) calculation. MISO ELCC for the term of the QF contract is calculated pursuant to the MISO Business Practices Manual (BPM) effective at the time of the QF contract execution. The currently effective ELCC calculation is provided in MISO BPM-011-r16 § 4.2.3, which recognizes capacity based on accumulated, historical performance.

3 Tr 292. According to Mr. Jester, his proposed language will allow future QF developers to estimate how much capacity value they should expect to receive, notwithstanding any changes to the calculation method. Mr. Jester emphasized that certainty about the calculation method for capacity is essential for developers obtaining project financing.

In response to Mr. Jester's recommended natural gas and transportation costs, Mr. Chilson averred that the cost of transportation should reflect the cost to transport gas from the Henry Hub to Consumers' City Gate, and not to the East North Central Region generally, as Mr. Jester proposed. Mr. Chilson reiterated that the company added a fixed and a variable cost to the base cost to represent transportation from Consumers' City Gate to the proxy NGCC plant to arrive at a delivered cost of gas. Mr. Chilson noted that although its proposed transportation costs were higher than the DTE Gas XXLT rate, it was still lower than the rate that Mr. Jester proposed. 3 Tr 228-229, Exhibit A-43.

Thomas V. Vine, a plant manager for Viking Energy of McBain, LLC, testified on behalf of IPPC. Mr. Vine recommended that the Commission adopt the 2017 EIA nominal forecast for natural gas prices. Mr. Vine noted that the Staff used the same forecast, but removed the embedded inflation and made inflation adjustments according to Global Insight. Mr. Vine opined that there is no indication of any problems with EIA's inflation adjustment, thus there was no need to use a different index for inflation of gas costs. 3 Tr 299, 312. Mr. Vine stated that Consumers' gas cost forecast uses proprietary information and averaging methods that are not publicly available, contrary to the Commission's preference set out in the July 31 order. 3 Tr 313.

With respect to variable O&M cost for an NGCC, Mr. Vine recommended using $3.60/MWh from EIA's Capital Cost Estimate for Utility Scale Electric Generating Plant for a conventional NGCC. Mr. Vine noted that this is the same amount (after adjusting for inflation) that Consumers used in its most recent integrated resource plan (IRP). Mr. Vine opined that the EIA rate for an advanced NGCC should not be used because the amount was based on manufacturers' representations and not actual operating data. 3 Tr 300-301. Mr. Vine raised concerns that there is only one advanced unit of the type on which Consumers bases its estimates (H-class) currently running in the United States, and there is insufficient operating information available on that unit. 3 Tr 301-302.

Mr. Vine observed that because Consumers is served by ANR Pipeline Company (ANR), the proxy unit would likely receive firm transportation service under rate FTS-3. Based on the latest ANR tariffed rate, Mr. Vine estimated:

> [F]irm transportation cost converted to $/kilowatt-month (kW-mo) (assuming 6,600 [sic] MMBtu/MWh heat rate) would be $1.228/kW-mo for deliverability and $1.158/kW-mo for capacity. These fixed costs would be added to the fixed O&M and included as part of the ICE payment. The variable commodity charge would be $0.0306/MMBtu.

3 Tr 304, Exhibit IPP-35.

Mr. Vine noted that in the July 31 order, the Commission failed to make a determination with respect to fixed O&M for an NGCC. Mr. Vine confirmed that IPPC's previously-filed estimate of $14.75/kW-year, which was based on Consumers' most recent IRP adjusted for inflation, should be adopted. Mr. Vine noted that this was consistent with the EIA estimate of $11.00/kW-year. However, Mr. Vine pointed out that the EIA estimate did not include property taxes, insurance, and asset management costs. 3 Tr 304-305.

Mr. Vine explained that IPPC continues to object to the application of ZRCs to QFs, noting that although ZRC capacity credit is assigned to Consumers' facilities, this is not how the company recoups its costs. Mr. Vine testified that using the same ratio of ZRC's to nameplate capacity as the company used in Exhibit A-15, he calculated that an NGCT with a nameplate capacity of 210 MW would receive 175 ZRCs, resulting in a levelized capacity payment of $143,536. 2 Tr 305-306, Exhibit IPP-33. Mr. Vine testified that he generally agreed with the company's NGCT inputs, but noted that the discount rate to be applied should be 7.65% and the levelized fixed charge rate should be 12.709%, in accordance with the Commission's order to use the inputs contained in Staff's Exhibit S-11, except for fixed O&M. Correcting these inputs results in a rate of $119,613/MW-year and $143,536/ZRC-year. 3 Tr 317, Exhibit IPP-33.

Mr. Vine testified that the rates for capacity and energy established by the Commission may affect the future viability of several IPPC members' operations, pointing out that biomass and hydro facilities provide an important hedge against future increases in gas commodity costs. 3 Tr 306. And, in response to the July 31 order, Mr. Vine presented proposed Standard Offer tariffs containing IPPC's inputs (Exhibits IPP-37 and IPP-38) and without those inputs (Exhibit IPP-39).

In rebuttal to Mr. Harlow's inputs for fixed O&M for the proxy NGCT unit, Mr. Vine observed that the Commission directed the parties to use the company's amounts for this component, as shown in Exhibit A-15. Mr. Harlow's fixed O&M cost, however, did not correspond to this amount, whereas, according to Mr. Vine, Consumers' fixed O&M numbers in Confidential Exhibit A-40 are correct. Mr. Vine also took issue with the Staff's fixed O&M input for the NGCC proxy unit, shown in Exhibit S-14, surmising that the Staff's number was a computation error. Mr. Vine noted that in Exhibit S-15, the Staff used a cost of $14.62/kW-year, which is comparable to IPPC's recommendation of $14.75/kW-year. 3 Tr 311. Mr. Vine also pointed out that it appeared that the Staff applied allowance for funds used during construction (AFUDC) to the wrong exhibit, thus leaving it out of the ICE calculation. 3 Tr 311-312. Finally, Mr. Vine testified that he disagreed with Consumers' ICE calculation, but agreed with the company's inclusion of start-up costs of 3% of fuel costs.

In response to Mr. Vine's claim that Consumers' transportation cost should be based on the firm contract for gas supply to the Zeeland plant, Mr. Chilson testified that the company utilizes a gas service agent to secure supply, and thus does not have a firm contract for transportation to Zeeland. Mr. Chilson also took issue with Mr. Vine's proposal to escalate the company's City Gate transportation cost differential, noting that there is no reason to expect the differential between the Henry Hub and Consumers' City Gate price to increase and that the cost of transportation has declined in recent years as more gas is sourced from areas closer to Consumers' City Gate. 3 Tr 234-235, Exhibit A-47.

In rebuttal to testimony by Messrs. Harlow, Vine, and Jester recommending the use of EIA data to forecast fuel price, Mr. Chilson testified that the use of unadjusted EIA values was inappropriate, observing that "[c]onsidering the 2009-2015 EIA forecasts for years 2010-2016, EIA made 28 predictions for natural gas prices and 26 of the predictions were higher than actuals. Not only were the predictions high but the percent error is as much as 237%." 3 Tr 225. Mr. Chilson added that although the New York Mercantile Exchange (NYMEX) market forecast has also been historically high, it is nevertheless more accurate than the EIA projection. Mr. Chilson reiterated that the company's Henry Hub natural gas composite forecast should be used for estimating future natural gas prices because this is the projection that Consumers uses for estimating gas cost in its power supply cost recovery plan cases. However, Mr. Chilson recommended that if the Commission decides to use the EIA forecast it should be adjusted using market forwards. According to Mr. Chilson:

> Market forwards represent actual transactions and prices for which the market is willing to pay. I recommend using market forwards for a short term forecast and then applying the annual incremental price increase from the EIA forecast to adjust the forecast for years beyond this short term period.

3 Tr 226; Exhibit A-36.

Ms. Thyagarajan noted that although Mr. Vine's calculation was close to the company's NGCT capacity cost, the two calculations nevertheless differed because Mr. Vine used a fixed O&M gas transportation cost of $14.43 per kilowatt (kW), an amount that he did not explain. Ms. Thyagarajan also disagreed with Mr. Vine's inputs for an NGCC proxy unit, opining that it was inappropriate to use inputs from the company's 2013 IRP, noting that the company completed an internal IRP in 2015. Ms. Thyagarajan testified that the inputs that Consumers used for this case are based on the company's most recent electric supply planning, completed this year. 3 Tr 247-248. Similarly, Ms. Thyagarajan disagreed with the EIA variable O&M forecasts used by IPPC and ELPC, and the NGCC fixed costs used by the Staff, on grounds that variable O&M should be based on the advanced technology Consumers would use. 3 Tr 248-249, Exhibit A-41. She observed that the Staff's ICE payment was $7.68/MWh rather than the company's $5.17/MWh. Ms. Thyagarajan also disputed ELPC's calculation of ICE, noting that the computation was inconsistent with the July 31 order because line losses should not be applied to the ICE payment.

In response to IPPC's and ELPC's proposed Standard Offer tariffs, Mr. Troyer testified that IPPC's tariff failed to recognize the Commission's determination that the MISO ZRC capacity construct should apply to all resources. Mr. Troyer added that the Staff's recommended language concerning ZRCs was sufficient and that ELPC's recommendation to include language requiring the company to procure ZRCs from MISO was unnecessary.

<u>Positions of the Parties</u>

Consumers argues that its inputs are the only ones that represent the actual costs that the company would avoid when purchasing from a QF. Accordingly, Consumers urges the Commission to approve its nominal Henry Hub natural gas forecast presented in Exhibit A-36. Consumers notes that the forecast is derived from multiple expert sources and is the same one that the company uses for energy supply planning. Although the Commission expressed a preference for publicly-available information, Consumers maintains that EIA forecasts tend to overstate actual prices and are therefore less reliable than the company's composite forecast. Nevertheless, if the Commission decides that a forecast based on EIA data is preferable, Consumers provided an alternative EIA forecast, which uses market forwards for a short-term forecast and then applies the annual incremental price increase from the EIA forecast to adjust the forecast to years beyond the short-term period.

For gas transportation, Consumers calculated the difference between the Henry Hub price and the price at the company's City Gate, arriving at a cost of $0.08/MMBtu. Then, Consumers calculated a transmission rate from the City Gate to the proxy plant based on an XXLT rate resulting in an annual charge of $3.5 million and a variable charge of approximately $0.23/MMBtu. Consumers asserts that the Commission should reject IPPC's criticisms of its transmission cost calculation, noting that the calculation results in amounts that are similar to other published large customer tariffs.

With respect to avoided NGCT and NGCC costs and ICE payment, Consumers maintains that it updated these amounts as directed by the May 31 and July 31 orders. Consumers notes that it included recommendations for NGCC variable cost and start-up fuel costs, which are issues that were not previously resolved. Accordingly, Consumers recommends that the Commission approve the company's nominal NGCC variable cost forecast, including ICE and line losses. *See*, Exhibit A-41. Consumers argues that its variable O&M costs are based on the next unit that the company would build.

The Staff recommends that the Commission adopt its proposed levelized energy payment and energy payment schedule, which are based on the EIA 2017 Annual Energy Outlook, noting that it does not agree with Consumers' proposal to adjust the forecast by applying a change rate to five-year futures contracts. The Staff contends that Consumers' proposal results in a gas price forecast that is lower than the EIA forecast every year "since the Company is only applying the average change rate of the EIA forecasts and not the actual average gas price." Staff's brief, p. 3, quoting

3 Tr 283. The Staff maintains that it is preferable to use transparent, publicly-available EIA forecasts with an adder for transportation based on Consumers' data.

The Staff asserts that it updated its proposed avoided costs for NGCT and NGCC proxy units in accordance with the Commission's previous orders. The Staff also points out that it advocates, and the company supports, a simplified method for calculating energy cost using an energy price schedule calculated as nominal costs in each year of the contract term.

The Staff recommends that the Commission adopt its Standard Offer set forth in Exhibit S-17, with one modification. The Staff suggests that the on-peak and off-peak LMP portions of its tariff be modified to incorporate certain amounts from Consumers' Exhibit A-46:

> Exhibit A-46 shows the calculation used to increase the LMP energy payment to reflect line losses and the addition of Fixed ICE. Column (e) is described as On-Peak LMP (Inc. Losses) Nom $/MWh Column (c) x 1.0237. However, this formula is only correct for the first number in the Column (e). The calculated numbers for Year 2018 through 2036 appear to be using the Off-Peak Column in the calculation instead of the On-Peak number. Staff recommends the Commission adopt the base On- and Off-Peak LMP projections in Columns (c) and (d).

Staff's brief on second reopening, p. 5.

IPPC argues that the Commission should use reasonable and transparent inputs to the hybrid-proxy models. Accordingly, IPPC supports the use of nominal EIA data for the natural gas price projection. IPPC points out that although the Staff also began with the EIA data, it then made inflation adjustments using proprietary information and models that defeat the purpose of using public information. Like the information that should be used for fuel price, IPPC also advocates the use of EIA information for gas unit capital costs, until such time as an advanced unit is built and actual costs are known.

With respect to gas transportation costs, IPPC contends that these costs should be based on inter- and intrastate firm transportation contracts adjusted for inflation. IPPC maintains that

Consumers' transportation estimates are neither reliable nor reasonable because they are based on outdated information. Based on its projections, IPPC requests that the Commission adopt the amounts and schedule that it supports for the energy portion of the payment, including ICE. *See*, Exhibits IPP-33, IPP-34, and IPP-40. Finally, IPPC urges the Commission to adopt its Standard Offer set forth in Exhibit IPP-39, noting that its proposed tariff does not apply the MISO ZRC construct, on grounds that ZRCs are not an appropriate means to determine cost and are simply used for resource adequacy.[5]

ELPC recommends that the Commission adopt the regional EIA forecasted natural gas delivered price shown in Exhibits ELP-16 and ELP-17. According to ELPC, because the delivered price already includes transportation, the fuel cost calculation could be simplified by adopting the regional projection. In addition, the prices are publicly available and expressed in nominal dollars, so an additional inflation adjustment is unnecessary. If the Commission decides not to use the regional forecast, ELPC maintains that it would be reasonable to either adopt the forecasts for gas and transportation recommended by IPPC or those recommended by the Staff.

For variable O&M costs, ELPC again contends that the Commission should rely on public information, noting that both it and IPPC relied on EIA data with different methods for applying inflation. ELPC states that either method is acceptable. ELPC recommends that the Commission adopt the Staff's proposed amount for ICE, noting that it made an error in its own calculation of ICE, and agreeing with the Staff that ICE should be fixed and not escalated. ELPC further contends that, because ICE is applied to the avoided energy calculation, and because line losses are a measure of how energy production is affected by QF generation, then line losses should be

[5] IPPC also filed a petition for rehearing on the Commission's decision to apply the ZRC capacity credit to all QF resources. The petition for rehearing is addressed below.

applied to the full avoided energy cost, e.g., the energy cost plus ICE. Finally, ELPC suggests that language clarifying the method for calculating ELCC should be added to the Standard Offer, observing that the Staff and IPPC do not object to the inclusion of this language, and Consumers simply deems it unnecessary.

In its brief, GLREA requests that:

> [T]he Commission in its fact-finding and judgments concerning the various presentations of the parties, . . . implement and adopt a balanced approach that would carry out the purposes and objectives of PURPA, so as to preserve and enhance the opportunities applicable to independent, non-utility affiliated, independent power producers. GLREA urges that existing QF contracts must be honored based upon constitutional, contract, and judicial precedent grounds, but also, that a balance needs to be honored as between the purposes and objectives of PURPA, in contrast to utility stockholder interests, to achieve optimal ongoing long-term results in furtherance of the public interest.

GLREA's brief, pp. 3-4.

Discussion

1. IPPC's Petition for Rehearing

IPPC asserts that the Commission's decision in the July 31 order to apply ZRC capacity credit to all QF resources, not only solar and wind, violated Mich Admin Code, R 792.10436 (Rule 436) and R 792.10437 (Rule 437).[6] According to IPPC, because Consumers did not file a petition for rehearing of the May 31 order, and instead raised the issue in its testimony in the reopened proceeding,[7] it was improper for the Commission to revisit the issue of how ZRC capacity credit

[6] In the May 31 order, the Commission agreed with the Staff that the MISO ZRC capacity structure should apply to intermittent resources like solar and wind only. In the July 31 order, the Commission, on further consideration of the issue, found that ZRCs should be applied to all QF resources.

[7] IPPC points out that it filed a motion to strike Consumers' testimony concerning the application of ZRCs, but that motion was withdrawn per the agreement of the parties. IPPC states: "In the course of agreeing not to pursue the Motion to Strike, IPPC never waived the larger

should be assigned to QFs. IPPC further maintains that because it did not receive proper notice that the Commission might review ZRC capacity credit, the record on this issue is not complete, and IPPC's right to due process was violated. IPPC also requests clarification regarding whether the application of the ZRC construct to "new contracts" means contracts for new facilities only, or whether it includes new contracts with existing facilities.

Citing *PáTu Wind Farm, LLC v Portland General Electric Company*, 150 FERC ¶ 61,032 (2015), IPPC further claims that:

> [T]he Commission's application of ZRCs to reduce the amount of a QF's capacity the utility must take, and thus compensate, violates PURPA. As the IPPC stated in its February 9 Initial Brief in this proceeding, under [Federal Energy Regulatory Commission's] FERC's rules, the measure of the amount of capacity that should be paid for by the utility is whatever the "net output" the QF is offering to the utility for purchase under a long-term contract, not what the utility states that it receives as a reliability credit in the MISO Market.

IPPC's petition for rehearing, p. 14.

IPPC also contends that the application of ZRCs to existing QFs that are currently under contract is discriminatory when compared to utility-owned generation. IPPC points out that although MISO applies ZRCs to Consumers' generation for capacity demonstration purposes, this is not how the company recovers the costs of its generation.

> In fact, Consumers' true intermittent resources – its Company-owned or contracted wind and solar ones, and its 13 Company-owned hydroelectric facilities – are not subject to any MISO market construct that reduces their cost recovery based on ZRCs. All of Consumers Energy's Company-owned or contracted resources enjoy full regulated rate recovery unencumbered by a reduction in payment based on ZRCs. In sum, the ZRC construct is neither an "avoided cost" nor an "input," but rather a resource adequacy mechanism that Consumers is advocating be used to reduce payments to QFs for the operation of their facilities.

IPPC's petition for rehearing, p. 17.

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argument that the issue of ZRCs was not properly before the Commission following the May 31 Order, which appeared to have settled it." IPPC's petition for rehearing, p. 5.

Finally, IPPC disputes the Commission's finding in the May 31 order, p. 32, that, "IPPC has had the opportunity to present a tariff or provide comments on the proposed tariffs presented by the Staff and Consumers, in both phases of this proceeding, but declined to do so." IPPC characterizes the statement as both offensive and untrue. While IPPC admits that it did not propose a Standard Offer as part of the proceedings, it provides an exhaustive list of citations to testimony and briefing where it commented on the tariff proposals of other parties.[8] IPPC concludes that its request for a technical conference was properly before the Commission and should not have been rejected. Accordingly, IPPC repeats its request for a technical conference to address the Standard Offer.

In response, Consumers argues that there is no merit to IPPC's claim that the Commission violated its own rules in addressing the ZRC issue. Consumers points out that "the Commission reconsidered an issue, based on the testimony it had before it, in the middle of an ongoing proceeding. IPPC's argument fails to recognize the unique circumstances of the case at hand." Consumers' response, p. 4. Consumers further contends that "[s]imply by the act of retaining jurisdiction, the Commission has the ability to modify its previous rulings or orders." *Id.*, FN 4.

Consumers argues that the company's testimony in the reopened proceeding was responsive to the Commission's directive to provide necessary inputs to the capacity and energy models. Although IPPC argues that the assignment of capacity credit was not an "input," Consumers disagrees. Consumers further claims that IPPC's due process rights were not violated because it had the opportunity to cross-examine the company's witness or provide rebuttal on the issue of ZRC capacity credits.

[8] IPPC also quoted at some length from its brief filed after the first reopened proceeding and attached some 95 pages of statements from IPPC members as well as all of the testimony and briefing it filed in the initial proceedings.

With respect to the substantive issue of using the ZRC construct for capacity for all QFs, Consumers maintains that there is no violation of PURPA. According to Consumers:

> The use of ZRCs ensures that the capacity provided by a QF is in the same units that the MISO capacity planning rules require. 2 TR 300. It also ensures that the pricing for QF capacity is based on the units and timeframe that MISO capacity planning rules require in order for the Company's payment to the QF to be commensurate with the costs that would be avoided by the Company. 2 TR 300. The use of ZRCs is essential to determining the Company's capacity need because MISO Load Serving Entities, like Consumers Energy, must annually provide certain load forecast information to MISO, and MISO takes that information and adds a reserve margin in Unforced Capacity ("UCAP") to arrive at each Load Serving Entities' Planning Reserve Margin Requirement ("PRMR"). Resources are awarded ZRCs by MISO, and only ZRCs can be used to meet the Company's PRMR. 2 TR 300. If the Company were forced to buy capacity from QFs in the form of MWs, without taking into account ZRCs, all capacity purchased from the QF may not be recognized by MISO which would force the Company and its customers "to purchase additional capacity due to the QF providing less capacity in actuality than what was contracted for pursuant to avoided cost rates." 2 TR 326.

Consumers' response, pp. 7-8 (footnote omitted). Consumers adds that the application of ZRCs to QF capacity is not discriminatory and that IPPC's claim that this is not how the utility recovers its costs is misplaced. Therefore, Consumers maintains that IPPC's petition for rehearing should be rejected on grounds that it does not meet the standards for rehearing under Rule 437.

Finally, Consumers argues that the Commission properly rejected IPPC's request for a technical conference on the Standard Offer. Consumers points out that the Commission relied on the company's argument that IPPC did not comment on the specific language in the Standard Offers proposed by the Staff and the company, but instead focused its critique on broader issues that the Commission already decided in the May 31 order. Consumers reiterates that IPPC has had over a year to either provide its own proposed Standard Offer tariff or provide specific suggestions for wording changes to the tariffs that were proposed by the Staff and the company. Accordingly, Consumers submits that the Commission properly rejected IPPC's request.

Rule 437(1) states the standards for filing a petition for rehearing:

> A petition for rehearing based on a claim of error shall specify all findings of fact and conclusions of law claimed to be erroneous with a brief statement of the basis of the error. A petition for rehearing based on a claim of newly discovered evidence, on facts or circumstances arising subsequent to the close of the record, or on unintended consequences resulting from compliance with the decision or order shall specifically set forth the matters relied upon.

The Commission has repeatedly held that a petition for rehearing is not simply an opportunity to reargue a position or express disagreement with the Commission's decision. Unless a party can show the decision to be incorrect under the criteria set forth in Rule 437, the Commission will not grant rehearing.

The Commission finds that IPPC's petition for rehearing with respect to purported violations of the Commission's Rules of Practice and Procedure should be denied. As Consumers points out, the May 31 order was interim in nature; the Commission retained jurisdiction over the proceedings, and IPPC had ample opportunity to respond to Consumers' testimony regarding the application of ZRCs to all QF resources through cross-examination or rebuttal in the reopened proceeding. And IPPC did, in fact, respond. *See, e.g.,* IPPC's brief on first reopening, pp. 7-10.

The Commission reiterates its finding from the July 31 order that "[there is] no justification to limit the application of ZRC capacity credits to only wind and solar, especially considering the fact that MISO applies ZRCs to all generating units, whether company-owned or not[,]" thus, IPPC's claims that the application of ZRCs to QF capacity for all generators has been addressed. The Commission further notes that IPPC's reliance on *PáTu Wind* is erroneous. In *PáTu Wind*, the issue before the FERC concerned wind energy integration costs imposed on the QF by the utility. And while the FERC indeed determined that the QF was entitled to sell its "entire net output" to the utility at avoided cost, the output to which the FERC referred was energy, not capacity. *PáTu Wind, supra,* FN 7. Here, the application of MISO ZRCs to capacity in no way reduces the QFs right to sell 100% of its energy output to the utility, consistent with *PáTu Wind*.

The Commission emphasizes that, for computing capacity, the ZRC construct provides a data-driven, transparent, and consistent manner to measure the capacity associated with a particular generating resource, and therefore is as appropriately applied to QFs as it is to the company's own resources.[9]

The Commission also agrees with Consumers that IPPC's claim about the company's cost recovery for its own generating units is misplaced. First, IPPC fails to recognize that only reasonably and prudently incurred costs are recoverable in rates, and the Commission can (and has) limited cost recovery for older, less economical units, with the result that some of these generating units have been, or will be, closed.

Second, avoided cost is not a measure of the utility's or QF's cost of service or embedded costs, as IPPC appears to argue. PURPA is intended to provide non-discriminatory access to the utility's system by QFs, with the assurance that generators will be paid at the incremental cost to produce energy or capacity that the utility would otherwise generate or produce. Importantly, avoided costs are intended to be forward looking, not based on historical costs, for both new and renegotiated PURPA contracts. As the Commission has previously explained, given the significant reductions in generation costs, coupled with the creation of the MISO market, the avoided costs established almost 30 years ago are no longer defensible under current market conditions. Thus, if the Commission were to set avoided costs today to cover the higher costs of some existing generators, it would result in ratepayers subsidizing uneconomic generation and would distort the overall market by providing an excessive payment to any new generation that

[9] In response to IPPC's request for clarification concerning the application of the ZRC capacity construct, the Commission reaffirms that while unexpired contracts are in no way affected by the new avoided cost method or costs established in this proceeding, all new contracts, for both new and existing generators, will be adjusted in accordance with the capacity credit assigned by MISO.

can produce energy and capacity below that price. This is not consistent with PURPA, and it would not be equitable or reasonable.

As a result, some QFs may compete effectively under the new avoided cost rate; others may not be able to remain financially viable, and others may require changes to their revenue or cost structure. As noted previously, this is indicative of a broader trend in the electric industry, in which the cost of new generation is declining and is more economical than the embedded cost of existing generation. The Commission understands that for many QFs who have been operating within set revenues for decades, 30 years of industry cost declines will occur essentially overnight. This is in contrast to an entity like a utility with a large generation portfolio, who has experienced a smoothing effect with individual units phasing in and out over the same period. The Commission is sympathetic to the impact this will have on QFs who have provided a renewable, domestic and diverse source of electricity for many years. They have also provided numerous positive tangential benefits to their surrounding communities and the State of Michigan. However, under PURPA, these positive non-energy related societal impacts are not factored into the calculation of avoided cost and therefore have not been reflected in this proceeding.

Finally, the Commission emphasizes that it is not possible to establish all of the other avoided costs that may be taken into account for an individual QF as part of a negotiated contract. For example, some QFs may be able to provide overall system support, black start service, emergency power supply, voltage support, or the ability to quickly ramp up or down, among other significant benefits. *See, e.g.*, 18 CFR 292.304(e). Accordingly, as part of its contract negotiations, Consumers shall, on a case-by-case basis, take into consideration these additional benefits even if the values of these additional services cannot be precisely quantified.

Finally, with respect to IPPC's claim that the Commission improperly rejected its request for technical conference on the Standard Offer, the Commission agrees that it would have been more accurate for the Commission to have pointed out that IPPC failed to make specific comments on the language in the Standard Offers that was proposed by the Staff and Consumers. That said, the Commission did adopt some of IPPC's (and others') recommendations with respect to the Standard Offer, thus IPPC's testimony and briefing on the subject were not ignored or dismissed out-of-hand. The Commission therefore finds that this part of the request for rehearing should be denied on grounds that it merely expresses disagreement with the Commission's decision.

2. Natural Gas Combustion Turbine Inputs

The Commission finds that the inputs provided by Consumers for the proxy NGCT unit comport with the findings in the July 31 order and should be adopted. As Consumers explained in rebuttal, the Staff's inputs and calculation contained some errors which, when corrected, result in the same avoided capacity cost as that reported by the company. IPPC's calculation similarly appears to contain an error with respect to the fixed O&M amount, although the overall result was similar to that computed by the company. Accordingly, the Commission adopts the avoided capacity cost of $117,203/MW-year, or $140,505/ZRC-year, proposed by Consumers.

3. Natural Gas Commodity and Transportation Costs

As discussed in more detail above, Consumers recommended the use of its composite nominal Henry Hub forecast for natural gas costs, coupled with transportation costs from Henry Hub to Consumers' City Gate and then from the City Gate to the location of the proxy plant. The Staff accepted Consumers' forecasted transportation costs but advocated the use of EIA's Henry Hub projection. IPPC agreed with the use of EIA data for fuel cost, but argued, *inter alia*, that transportation costs should be based on a firm contract. ELPC recommended the use of the nominal EIA forecast of the cost of delivered gas to the region, thereby dispensing with the need for a separate calculation of transportation and delivery costs.

The Commission agrees with ELPC, that the use of the regional EIA 2017 Forecasted Natural Gas Delivered Price, shown in Exhibit ELP-16, is most reasonable. As ELPC pointed out, the delivered price already includes transportation, thus the calculation of the commodity and delivery cost is simplified, transparent, and less subject to inconsistent assumptions or computational error. In addition, as Consumers tacitly admits, the company does not solely source gas from the Henry Hub, thus the use of the price differential between Henry Hub and Consumers' City Gate does not fully represent Consumers' transportation costs. Finally, the EIA prices are publicly available and are expressed in nominal dollars so that an additional inflation adjustment is unnecessary.

4. Other Natural Gas Combined Cycle Inputs and Investment Cost Attributable to Energy

Several parties point out that the July 31 order did not address NGCC variable O&M costs or NGCT and NGCC fixed O&M costs for use in the ICE calculation. Consumers contends that, for NGCC variable O&M, the company's starting value of $2.27/MWh should be used because it reflects the type of advanced NGCC unit that the company would build. Conversely, ELPC and IPPC recommend that the EIA amount for a conventional NGCC, starting at $3.50/MWh, should be adopted for this input because the company's information is based on manufacturer's representations, and not the actual operation of an advance unit, and because Consumers' inputs are not publicly available.

The Commission agrees with Consumers that for setting avoided costs in this proceeding, the company's input for NGCC variable costs should be used in the calculation. The Commission notes that the EIA value for variable O&M for an advanced NGCC is lower than what Consumers proposes and, as the company points out, it would be more likely to build an advanced unit if it were to build. Nevertheless, this input should be revisited in the company's next PURPA review when actual operating information for an advanced NGCC unit will presumably be available.

As the Commission explained in the May 31 order, ICE represents the difference between the total fixed costs of an NGCC and an NGCT. The Commission has previously determined that for the NGCT, it would adopt Consumers' fixed cost amounts. For the total fixed costs of an NGCC, the Commission again finds that Consumers' proposed amount for an advanced NGCC is more reasonable than EIA information which, although publicly available, appears less reliable than the company's information. In addition, the Commission finds that ICE should be fixed, rather than escalated, as suggested by the company and the Staff, and as agreed to by ELPC. Therefore, based on the inputs adopted above, the Commission approves a fixed ICE amount of $7.65.

Consumers contends that the 2.37% credit for avoided line losses should be applied to the energy portion of the calculation only, with ICE added afterward. ELPC argues that, because ICE is part of energy, the 2.37% line loss credit should be applied to the sum of the energy cost plus ICE. The Commission agrees with ELPC that, because ICE recognizes the lower energy costs of an NGCC compared to an NGCT, and because ICE is a component of energy, the line loss credit should apply to both energy avoided cost and ICE.

The Commission also agrees with Consumers' recommendation to include start-up costs as part of the NGCC model, and, the Commission agrees with the Staff, Consumers, and ELPC that the simplified calculation method proposed by the Staff should be implemented as shown in Exhibits S-16 and ELP-17.

5. Standard Offer Tariff

In light of the Staff's recommended correction to its LMP forecast, with which the Commission agrees, the only remaining contested issue concerning the Standard Offer tariff, is whether or not to include language suggested by ELPC concerning the calculation of ELCC.[10] It appears that Consumers misconstrues ELPC's proposal, which does not require the company to purchase ZRCs on behalf of the QF. In essence, ELPC is proposing to fix for the term of the contract the method for calculating ELCC that MISO is implementing at the time the contract is executed, notwithstanding any potential future changes to that method. In balancing the QF's need for certainty for project financing purposes, with the possibility that the method for calculating ELCC may undergo changes (which may result in a modest increase or decrease in capacity payment), the Commission finds that ELPC's language is reasonable and should be included in the Standard Offer. This determination is reflected in Attachment 2 to this order.

In the July 31 order, p. 26, the Commission concluded that:

> [F]or certain existing QFs, particularly run-of-the-river hydro, the application of MISO capacity credit represents a significant departure from the way that capacity was valued in the past. Accordingly, and as discussed in more detail *infra*, run-of-the-river hydro <u>only</u> may opt for a levelized energy payment in lieu of an escalating payment.

The Commission clarifies that the above quoted statement applies to energy avoided cost Option 2 (forecasted LMP price option) and to Option 3 (avoided NGCC plant option). In other words, only run-of-the river hydro can select a levelized payment for energy under the options where it is available.

Finally, the Commission notes the evolving language in the early termination provision in the Standard Offer, beginning with Exhibits A-1 and S-1, ¶ F in Consumers' and the Staff's initial filings:

> In the event that seller's Qualifying Facility ceases operations prior to the end of the term of the Power Purchase Agreement and the Company must replace the capacity supplied by seller in accordance with MISO's requirements, then seller shall

[10] The ELCC is a mechanism that credits capacity based on historic on-peak availability that can be converted to ZRCs. 2 Tr 153-154

> reimburse the Company for the positive difference, if any, between the cost incurred by the Company to replace seller's capacity and the cost the Company would have incurred to purchase such capacity from the seller under the Power Purchase Agreement ("Replacement Cost"). Any amounts due seller at the time operations cease shall be held until such time that Replacement Cost is determined and the net amount owed shall be paid by the party that owes it within 20 days after Replacement Cost is determined. The Company shall have no obligation to enter a subsequent Power Purchase Agreement with the seller until such time that any amounts due the Company pursuant to this paragraph are paid.

And ending with the currently proposed language in Exhibits A-34 and S-17, ¶ G:

> Sellers shall be required, based on the options made available by the Company, to select a form of security to cover the financial risk associated with the Company's cost for replacement capacity in the event the QF ceases operation prior to the end of the term of the Power Purchase Agreement. The amount of security required will be based on the estimated amount of capacity it will deliver and the term of the contract.

The Commission finds it reasonable for Consumers to require some form of security, in the event that a QF defaults; however, the Commission also finds that the various options for paying the security, as well as how the company will calculate the amount of the security deposit should be spelled out in the tariff. The Commission further finds that the amount of the deposit or escrow should be reasonable based on the total capacity expected to be provided over the life of the contract, and that the security deposit should be refunded as the term of the contract runs. Consumers shall update the Standard Offer accordingly prior to filing the tariff and implementing the Standard Offer.

6. Summary

The Commission commends the parties to this proceeding for their thorough and thoughtful analyses of the issues raised in confronting the complexities of avoided cost calculation for the first time in almost 30 years. Because of the diligence of the parties, the Commission believes that it has established avoided costs that are accurate and consistent with the requirements of PURPA.

The Commission also acknowledges the difficulty associated with setting new avoided costs and the need to monitor the development of PURPA projects going forward, given potential changes in capacity needs, fuel costs, and technology and construction costs. It has been 40 years since PURPA was enacted into law, and much has changed during that time—wholesale markets and retail competition have developed, stagnant load growth makes it more difficult to absorb costs without putting pressure on utility rates, and economic forces and technological advancement have driven the shift from electricity generated using coal to natural gas and renewables. Although the world has changed dramatically, PURPA has historically used conventional, fossil-fueled generating plants as a proxy for a utility's avoided cost, even though it may be more expensive than how the utility would actually secure equivalent amounts of incremental energy and capacity needed to meet customer demand.

The Commission observes that, except for situations where a utility is replacing large amounts of retiring generating capacity, the actual approaches to securing energy and capacity in the short to medium term do not necessarily entail building new, large-scale generation. Rather, energy resource additions tend to fall into three categories: (1) purchases of surplus energy and capacity from other energy and capacity suppliers through the MISO energy market, MISO PRA or through bilateral contracts; (2) the use of energy efficiency and demand response programs that help customers use less electricity overall and shift when they consume it; or (3) the use of renewables to provide low-cost energy, as a hedge against high fuel prices, and to comply with renewable portfolio standard requirements. Moreover, customers may pursue on-site generation to meet their energy needs in the future.

Notwithstanding these trends, the Commission found it reasonable at this time, and based on the record in this proceeding, to use a proxy gas plant to determine avoided costs. Further, the Commission found that using a 10-year timeframe to determine whether the utility requires additional capacity was appropriate, given Consumers' even longer planning horizon for its own capacity additions. In addition, a 10-year horizon is consistent with 18 CFR 302(b)(2).[11] The Commission notes, however, that the issue of determining the utility's capacity need was not fully fleshed out in this proceeding and merits further examination in the company's next PURPA review. In the meantime, if Consumers' capacity requirements are met over the subsequent 10 years, the company may make a filing so demonstrating and, after Commission approval, the capacity rate will be reset to the MISO PRA. Overall, the Commission's decisions in this case comport with the Commission's historical approach to PURPA (albeit with a shift from a coal to a natural gas proxy), and places QFs on an equal footing with the utility as required under the non-discrimination provisions of PURPA.

To summarize, in the three orders issued in this proceeding, the Commission found that the most appropriate method for determining Consumers' avoided capacity and energy costs was the Staff's hybrid-proxy method. This method assumes that if Consumers only required additional capacity, the company would build an NGCT, and if the company required additional energy, it would invest in an NGCC. The costs associated with these two types of units are then used to compute avoided capacity and avoided energy cost. In light of the difference between the total fixed costs of an NGCC and an NGCT, the Commission adopted the Staff's proposal to add ICE to the energy calculation, using the company proposed amount for fixed costs of an NGCT and NGCC.

[11] This section of the federal regulations requires the utility to make available to the public, at least every two years, "The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years[.]"

The Commission further found that because Consumers uses at least a 10-year planning horizon to project its own capacity needs, the same horizon should be used for the purpose of determining whether QFs should be compensated for capacity. As discussed above, if the company forecasts that no capacity is required in the next 10 years, Consumers shall make a filing so indicating, and upon Commission approval, the capacity price for new contracts shall be reset to the MISO PRA price.

For the NGCT proxy unit, the Commission adopted the Staff's inputs with the company's amounts for discount and fixed charge rates. For the NGCC, the Commission agreed with the company's heat rate and variable O&M costs, recognizing that if Consumers were to build an NGCC, it would build an advanced, rather than conventional, unit. For fuel cost and transportation, the Commission used the nominal EIA projection for gas delivered to the East North Central region, as proposed by ELPC. This approach combines publicly available information with a simplified approach for determining transportation costs.

As discussed in more detail in this and the July 31 order, the Commission decided that the MISO ZRC construct should apply to all new PURPA contracts. The Commission also found that expiring contracts for existing QFs shall be renewed at the full avoided cost rate (*e.g.*, including payment for both capacity and energy), whether or not Consumers forecasts a capacity shortfall. This determination recognizes that the capacity supplied by QFs with existing contracts is already included in the company's capacity portfolio.

For the Standard Offer, the Commission agreed that the design capacity should be set at 2 MW and that Standard Offer term lengths should be set at five, 10, 15, and 20 years at the option of the QF. The new design capacity represents a significant departure, with the size threshold increasing from 100 kW to 2 MW with a 20-year contract. Because generating technologies are rapidly changing, the Commission will monitor the performance of this new construct for the Standard Offer.

The Commission founds that,except for the 2.37% avoided line loss factor, which should be applied to both energy and ICE, there was insufficient evidence in this record to quantify or include other avoided costs in the Standard Offer. Nevertheless, Consumers shall consider other benefits provided by individual QFs on a case-by-case basis. Finally, the Commission agreed with ELPC that renewable energy credits belong to the QF under both the Standard Offer and negotiated PPAs, and that the next review of Consumers' avoided costs should be conducted in two years.

Going forward, the Commission believes that PURPA avoided costs should be integrated with capacity demonstration and IRP proceedings in order to more accurately assess capacity needs. The IRP proceedings are conducive to updating avoided costs, because the Commission will already be evaluating, in detail, utility-specific plans for any incremental generation or purchases along with their associated costs.

The non-confidential inputs to the NGCT and NGCC models, as well as the avoided energy and capacity cost calculations are set forth in Attachment 1 to this order. As discussed above, the Commission adopts the simplified format for reporting energy calculations and payments shown in Exhibits A-41, S-16, and ELP-17, and Attachment 1. Attachment 2 to this order contains the final Standard Offer tariff as modified by the determinations in this order and the orders issued on May 31, 2017 and July 31, 2017. As set forth above, Consumers shall submit more specific language concerning early termination of PPAs under the Standard Offer when it files its tariff.

THEREFORE, IT IS ORDERED that:

A. Avoided cost inputs and calculations for capacity and energy for Consumers Energy Company, as set forth in Attachment 1 to this order, are approved.

B. Consumers Energy Company's Standard Offer tariff, contained in Attachment 2 to this order, is approved for implementation on and after December 5, 2017, subject to the company's clarification of the early termination paragraph as discussed in this order.

C. Within 15 days of the date of this order, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment 2 to this order.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of November 21, 2017.

Kavita Kale, Executive Secretary

Proxy Plant Inputs

Natural Gas Combustion Turbine		
	Input	Source
Discount Rate	7.55%	A-40
Fixed Charge Rate	12.33%	A-40
Winter NDC	210	A-40
Summer NDC	186	A-40
Zonal Resource Credits	175	A-40
Operating Life (Yrs)	30	A-40
Capital Costs (2017 $K)	[redacted]	A-40
Capital Costs ($/KW)		A-40
Fixed O&M (Annual $K)	$3,030	A-40
$/MW-yr	$117,203	A-40
$/ZRC-yr	$140,505	A-40

Natural Gas Combined Cycle		
	Input	Source
Discount Rate	7.55%	S-16
Fixed Charge Rate	12.74%	S-16
Capacity	400	S-16
Heat Rate Btu/kWh	6600	S-16
Capital Costs (2017 $K)	478,651	S-16
Capital Costs ($/KW)	1,197	S-16
Fixed O&M (Annual $K)	9,766	A-40
Fixed ICE	$7.65	Calculated

Option 2: Forecasted Locational Marginal Prices

A	B	C	D
Year	**Annual On-Peak Average**	**LMP + Fixed Ice and Line Loss Factor Less $1 Administrative Fee ($/MWh)**	**Levelized LMP + Fixed Ice and Line Loss Factor Less $1 Administrative Fee ($/MWh)***
2017	$34.89	$42.55	
2018	$32.49	$40.09	
2019	$32.14	$39.73	
2020	$33.31	$40.93	
2021/5 Year	$34.55	$42.20	$42.10
2022	$36.26	$43.95	
2023	$37.19	$44.90	
2024	$38.97	$46.72	
2025	$40.15	$47.93	
2026/10 Year	$41.19	$49.00	$44.24
2027	$43.04	$50.89	
2028	$44.76	$52.65	
2029	$46.45	$54.38	
2030	$48.48	$56.46	
2031/15 Year	$49.78	$57.79	$46.66
2032	$51.15	$59.19	
2033	$52.65	$60.73	
2034	$54.79	$62.92	
2035	$55.93	$64.09	
2036/20 Year	$57.66	$65.86	$48.89

E	F	G	H
Year	**Annual On-Peak Average**	**LMP + Fixed Ice and Line Loss Factor Less $1 Administrative Fee ($/MWh)**	**Levelized LMP + Fixed Ice and Line Loss Factor Less $1 Administrative Fee ($/MWh)***
2017	$27.74	$35.23	
2018	$27.30	$34.78	
2019	$27.43	$34.91	
2020	$28.18	$35.68	
2021/5 Year	$29.11	$36.63	$36.39
2022	$30.19	$37.74	
2023	$31.03	$38.60	
2024	$32.86	$40.47	
2025	$34.07	$41.71	
2026/10 Year	$34.99	$42.65	$38.30
2027	$36.33	$44.02	
2028	$37.63	$45.35	
2029	$38.98	$46.74	
2030	$40.42	$48.21	
2031/15 Year	$41.76	$49.58	$40.36
2032	$43.05	$50.90	
2033	$44.34	$52.22	
2034	$45.99	$53.91	
2035	$47.17	$55.12	
2036/20 Year	$48.48	$56.46	$42.25

Source	A-46
DISCOUNT RATE	7.55%
Fixed Ice	$7.65
Line Loss Factor	2.37%

*Only applicable to run-of-river hydro facilities.

Option 3: Proxy Pant Variable Price Forecast								
A	B	C	D	E	F	G	H	I
Year	**Natural Gas Price Forecast**	**Start-Up Fuel**	**NGCC Plant Heat Rate**	**Variable O & M**	**Base Energy Price**	**Base Energy Price Plus Fixed Ice**	**Energy Payment + ICE and Line Loss Factor Less $1 Administrative Fee**	**Levelized Energy Payment + ICE and Line Loss Factor Less $1 Administrative Charge***
					Col (B+C)*D/1,000+(E*1000)	Col F + ICE	Col G * Line Loss -1	Col H Levelized
Source	ELP-17	A-45		A-45		$7.65	1.0237	
	$ per MMBtu	$ per MMBtu	Btu/kWh	$ per kWh	$ per MWh	$ per Mwh	$ per Mwh	$ per Mwh
2017	$3.50	$0.10	6,600	0.00227	$26.01	$33.66	$33.46	
2018	$3.83	$0.10	6,600	0.00233	$28.25	$35.90	$35.75	
2019	$4.21	$0.09	6,600	0.00239	$30.79	$38.44	$38.35	
2020	$4.69	$0.09	6,600	0.00245	$33.98	$41.63	$41.62	
2021	$4.91	$0.09	6,600	0.00252	$35.49	$43.14	$43.16	$38.10
2022	$5.01	$0.09	6,600	0.00258	$36.26	$43.91	$43.95	
2023	$5.18	$0.10	6,600	0.00265	$37.52	$45.17	$45.24	
2024	$5.45	$0.11	6,600	0.00271	$39.41	$47.06	$47.17	
2025	$5.72	$0.11	6,600	0.00278	$41.29	$48.94	$49.10	
2026	$6.02	$0.12	6,600	0.00284	$43.34	$50.99	$51.20	$41.78
2027	$6.41	$0.13	6,600	0.00291	$46.07	$53.72	$53.99	
2028	$6.82	$0.14	6,600	0.00297	$48.92	$56.57	$56.91	
2029	$7.15	$0.15	6,600	0.00304	$51.25	$58.90	$59.30	
2030	$7.40	$0.15	6,600	0.00311	$52.92	$60.57	$61.01	
2031	$7.60	$0.16	6,600	0.00318	$54.40	$62.05	$62.52	$45.47
2032	$7.78	$0.17	6,600	0.00325	$55.74	$63.39	$63.89	
2033	$7.86	$0.17	6,600	0.00333	$56.33	$63.98	$64.50	
2034	$8.11	$0.17	6,600	0.00340	$58.06	$65.71	$66.27	
2035	$8.56	$0.18	6,600	0.00348	$61.16	$68.81	$69.44	
2036	$8.74	$0.19	6,600	0.00356	$62.47	$70.12	$70.78	$48.31

*Only applicable to run-of-river hydro facilities.

(Continued From Sheet No. C-58.00)

C18. STANDARD OFFER – PURCHASED POWER

A. Availability

The Standard Offer is available for the purchase of electrical energy and capacity, as needed, supplied by a seller's eligible Public Utility Regulatory Policies Act of 1978 ("PURPA") Qualifying Facility. The Qualifying Facility must meet the requirements established by the Federal Energy Regulatory Commission including but not limited to, 18 C.F.R. §§ 292.203, 292.204, and 292.205. The Standard Offer is not available for electric service supplied by the Company to a seller who has negotiated rate credits or conditions with the Company which are different from those below. To qualify for the Standard Offer, a seller shall execute a standard Power Purchase Agreement with the Company.

The participating seller is required to install and operate a generation system with design capacity of no less than 1 kW and no more than 2 MWac.

Service hereunder shall be restricted to the Company's purchase of energy or energy and capacity from the seller's generating facilities up to the Contract Capacity specified in the Power Purchase Agreement which may be operated in parallel with the Company's system. Power delivered to the Company shall not offset or be substituted for power contracted for, or which may be contracted for, under any other schedule of the Company. If a seller requires supplemental, back-up, or standby services, the seller shall enter into a separate service agreement with the Company in accordance with the Company's applicable electric rates and Service Regulations approved by the Michigan Public Service Commission.

B. Distribution Requirements for Sellers Connected to Company System

(1) All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall install own, operate, and maintain all metering and auxiliary devices (including any telecommunication links, if applicable) connected to the Company System. Meters furnished, installed, and maintained by the Company shall meter generation equipment.

(2) Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8. Electric Interconnection and Net Metering Standards) service. The Company will determine the particular nature of the voltage in each case.

(3) If the seller's generating facility is connected to a distribution line serving other Company customers, then the point of delivery for energy measurement purposes shall be at the high voltage side of the generating facility's isolation transformer connecting the seller's generating facility to the Company's distribution system. If the seller's generating facility is not connected to a distribution line serving other Company customers, then the point of delivery for energy measurement purposes shall be at the point at which the radial line connecting the seller's generating facility to the Company's distribution system terminates at the first substation beyond the generating facility's isolation transformer.

(4) Hourly Interval Registering Meters are required for each generating unit served under this rate. For a seller in which the measurement of energy delivered to the Company is not located at the point of delivery, then electric losses as determined by the Company for losses between the energy measurement location and the point of delivery shall be deducted for billing purposes from the energy measurements thus made.

(Continued on Sheet No. C-60.00)

(Continued From Sheet No. C-59.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

B. Distribution Requirements for Sellers Connected to Company System (Contd)

(5) The seller must meet the Interconnection Standards referenced in Rule B8 of this Electric Rate Book, Electric Interconnection and Net Metering Standards, R 460.615 - R 460.628, for the class of generator installed. Per these standards, testing and utility approval of the interconnection and execution of a parallel operating agreement must be completed prior to the equipment operating in parallel with the distribution system of the utility. Additionally, the Company will confirm and ensure that an electric generator installation at the seller's site meets the IEEE 1547 anti-islanding requirements.

(6) The seller is required to obtain the characteristics of service from the Company prior to the installation of equipment. The Company shall provide the characteristics in writing upon request. In the event that the equipment proposed for connection is not compatible with these characteristics, the Company shall have no obligation to modify its distribution system or provide any monetary compensation to the seller.

Any service facilities shall be dedicated to the generator and shall not be shared with those providing service to any seller. The Company shall determine the characteristics of service. Should the installation of new Company distribution facilities be necessary for the equipment, all costs for the distribution facilities installed may be charged to the applicant in advance of construction as a nonrefundable contribution. If the applicant desires underground service facilities, the difference in cost between overhead and underground service facilities shall be charged to the applicant in advance of construction as a nonrefundable contribution.

(7) If, in the sole judgment of the Company, it appears that connection of the equipment and subsequent service through the Company's facilities may cause a safety hazard, endanger the Company facilities or the seller's equipment or to disturb the Company's service to customers and other sellers, the Company may refuse or delay connection of the equipment to its facilities.

A seller taking the Standard Offer is not eligible to participate in the Company’s Net Metering program. Sellers with unsatisfactory payment history on their delivery account are not eligible to participate.

(8) The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

C. Published Avoided Cost Rates

The capacity and energy rates applicable to the Standard Offer will be updated every two years based on the Company’s need for capacity and the Company’s avoided cost data reported to the Michigan Public Service Commission. Power Purchase Agreements with terms in excess of two years shall continue to receive the capacity rate and any applicable energy rate as provided in the Power Purchase Agreement.

D. Monthly Rate

System Access Charge - Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

(Continued on Sheet No. C-61.00)

(Continued From Sheet No. C-60.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Monthly Rate (Contd)

Energy – For all energy supplied by the seller, the seller shall receive an energy payment equal to one of the rate options below, as selected by the seller and applicable for the term of the contract. Rate Option 4A and 4B are only available to run-of-the-river hydro QFs. The line loss adjustment factor will be revised for future new Power Purchase Agreements when line losses are updated in general electric rate cases, as approved by the Commission.

Rate Option	Energy Rate $/kWh
1. As Available Rate	Actual MISO Day Ahead Locational Marginal Price (LMP) at the Company's CONS.CETR load node multiplied by 1 plus the line loss adjustment factor of 2.37% plus Fixed ICE of $0.00765/kWh** and less the Administrative Fee of $0.001/kWh.
2. LMP Energy Rate Forecast	Forecast of Day Ahead MISO LMP at the Company's CONS.CETR load node multiplied by 1 plus the line loss adjustment factor of 2.37% plus Fixed ICE of $0.00765/kWh** less the Administrative Fee of $0.001/kWh.

Year	On-Peak Energy Rate $/kWh	Off-Peak Energy Rate $/kWh	Year	On-Peak Energy Rate $/kWh	Off-Peak Energy Rate $/kWh
2017	$0.04255	$0.03523	2027	$0.05089	$0.04402
2018	$0.04009	$0.03478	2028	$0.05265	$0.04535
2019	$0.03973	$0.03491	2029	$0.05438	$0.04674
2020	$0.04093	$0.03568	2030	$0.05646	$0.04821
2021	$0.04220	$0.03663	2031	$0.05779	$0.04958
2022	$0.04395	$0.03774	2032	$0.05919	$0.05090
2023	$0.04490	$0.03860	2033	$0.06073	$0.05222
2024	$0.04672	$0.04047	2034	$0.06292	$0.05391
2025	$0.04793	$0.04171	2035	$0.06409	$0.05512
2026	$0.04900	$0.04265	2036	$0.06586	$0.05646

Rate Option	Energy Rate $/kWh
3. Proxy Plant Variable Rate Forecast	Projection of the variable costs of operating the proxy plant multiplied by 1 plus the line loss adjustment factor of 2.37% plus Fixed ICE of $0.00765/kWh** and less the Administrative Fee of $0.001/kWh.

Year	Energy Rate $/kWh	Year	Energy Rate $/kWh
2017	$0.03346	2027	$0.05399
2018	$0.03575	2028	$0.05691
2019	$0.03835	2029	$0.05930
2020	$0.04162	2030	$0.06101
2021	$0.04316	2031	$0.06252
2022	$0.04395	2032	$0.06389
2023	$0.04524	2033	$0.06450
2024	$0.04717	2034	$0.06627
2025	$0.04910	2035	$0.06944
2026	$0.05120	2036	$0.07078

(Continued on Sheet No. C-62.00)

(Continued From Sheet No. C-61.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Monthly Rate (Contd)

Rate Option	**Energy Rate $/kWh**			
	Additional Energy Rates **Rate Options 4A and 4B - Available to Run-of-River Hydro Only**			
4A. Levelized LMP Forecast	Levelized forecast of Day Ahead MISO LMP at the Company's CONS.CETR load node multiplied by 1 plus the line loss adjustment factor of 2.37% plus Fixed ICE of $0.00765/kWh** less the Administrative Fee of $0.001/kWh.			
Contract Term	5 Years	10 Years	15 Years	20 Years
On-Peak	$0.04210	$0.04424	$0.04666	$0.04889
Off-Peak	$0.03639	$0.03830	$0.04036	$0.04225
4B. Levelized Proxy Plant Variable Cost	Levelized projection of the variable costs of operating the proxy plant multiplied by 1 plus the line loss adjustment factor of 2.37% plus Fixed ICE of $0.00765/kWh** and less the Administrative Fee of $0.001/kWh.			
Contract Term	5 Years	10 Years	15 Years	20 Years
	$0.03810	$0.04178	$0.04547	$0.04831

Capacity – The seller shall receive a monthly capacity payment based on the proxy capacity payment rate and the units of capacity as indicated below. Payments shall be reduced by any applicable monthly Interconnection Cost.

The monthly capacity payment will be equal to the number of ZRCs that MISO determines the seller's Qualifying Facility can supply to the Company for the applicable MISO resource planning period multiplied by the applicable capacity rate expressed in such units of capacity. The current resource planning period is the planning year which runs from June 1st of each year through May 31st of the following year. If no historical generation data is available for the first year of generation a Qualifying Facility shall be assigned the MISO class average capacity credits by technology.

Capacity value paid to QFs does not depend on whether the Company actually obtains ZRCs for such capacity, only that the Company could obtain ZRCs for the QF capacity. Capacity value paid to a QF is in units of $ per ZRC-Month. MISO ZRCs are equal to the project's nameplate capacity (in MW_{AC}) modified by the MISO effective load carrying capacity (ELCC) calculation.

At the time the Contract is executed, the MISO ELCC calculation method shall be set for the term of the QF contract according to the MISO Business Practices Manual (BPM) calculation method effective at the time of the QF contract execution.

(Continued on Sheet No. 63.00

(Continued From Sheet No. C-62.00)

C18. STANDARD OFFER - PURCHASED POWER (Contd)

D. Monthly Rate (Contd)

The currently effective ELCC calculation is provided in MISO BPM-011-r16 § 4.2.3, which recognizes capacity based on accumulated, historical performance.

Monthly Capacity Payment
\$140,505/ZRC-Year ÷ 12 = \$11,709/ZRC-Month

E. Renewable Energy Credits

Renewable Energy Credits (RECs) are owned by the customer. The Company may purchase RECs from sellers that are willing to sell RECs generated. The Company will enter into a separate agreement with the customer for the purchase of any RECs.

F. Term

The seller may select a contract length of 5, 10, 15 or 20 years, but in no event shall the term of any Power Purchase Agreement expire prior to the end of a MISO planning period.

G. Early Termination

Sellers shall be required, based on the options made available by the Company, to select a form of security to cover the financial risk associated with the Company's cost for replacement capacity in the event the QF ceases operation prior to the end of the term of the Power Purchase Agreement. The amount of security required will be based on the estimated amount of capacity it will deliver and the term of the contract.

This provision is approved subject to the Company's clarification as discussed by the order. Such clarifying language shall be included in the Company's filed tariff.

H. Execution of Standard PPA

In order to execute the Standard PPA, the Seller must complete all of the general project information requested in the applicable Standard PPA. When all information required in the standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the Seller must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA. When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days.

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-18090

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on November 21, 2017 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
this 21st day of November 2017

Steven J. Cook

Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

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