REPORT ON THE IMPLEMENTATION OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 (PURPA)

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

MICHIGAN PUBLIC SERVICE COMMISSION
Department of Licensing and Regulatory Affairs
In compliance with Act 341 of 2016

April 20, 2018

Table of Contents

Introduction

Report Criteria

On April 20, 2017, Public Act 341 of 2016 (PA 341) became effective. Section 6v outlines new requirements for the Commission to implement title II, section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), a federal law. PA 341 requires that the Commission conduct a proceeding at least every five years to ensure that procedures and rate schedules, including avoided cost rates, are just and reasonable based on PURPA and Federal Energy Regulatory Commission (FERC) regulations and orders implementing PURPA. Within one year of the effective date of PA 341, and every two years thereafter, the Commission shall issue a report describing the status of qualifying facilities (QFs) in the state, the current status of power purchase agreements (PPAs) for each QF, and the Commission's efforts to comply with the requirements of PURPA. This is the Commission's first report to the legislature regarding PURPA in Michigan.

Public Utility Regulatory Policies Act of 1978

In 1978, Congress passed and the President signed the Public Utility Regulatory Policies Act, commonly referred to as PURPA. The main purpose of the act was to encourage the development of renewable electric energy and cogeneration resources without adversely affecting the retail rates of electric utilities. PURPA requires that electric utilities interconnect with a QF (provided the QF pays reasonable interconnection costs), purchase energy and capacity at the utility's avoided cost, and sell supplemental, backup, maintenance, and interruptible power (standby service) to the QF on a non-discriminatory basis.[1]

[1] Avoided costs means the incremental costs 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 itself or purchase from another source. CFR §292.101(6).

PURPA's "must purchase" obligation applies to all energy and capacity made available for sale and applies to all utilities. State utility commissions and non-regulated utilities have the responsibility to determine interconnection costs, establish avoided costs, and set rates for standby service.

Michigan PURPA History

In Case No. U-6798, the Commission initiated proceedings on March 17, 1981 (Initial Order) to implement the provisions of Section 210 of PURPA (16 USC 824a–3). Five additional orders were issued under the U-6798 docket. In the Initial Order, the Commission identified the following state regulatory authority obligations under PURPA and the federal regulations implementing it:

1. File a report with FERC describing implementation
2. Set avoided cost rates
3. Set a standard rate for QFs of 100 kW or less
4. Set rates for standby service
5. Address interconnection costs
6. Establish a procedure for handling complaints

The utility obligations are described below:

1. Purchase at avoided cost
2. Provide standby service
3. Provide interconnections to QF
4. File data

The Initial Order established interim rates for both purchased and standby power and required utilities to offer interconnections to QFs. A contested case process provided an in-depth review of PURPA implementation which culminated in an Order issued on August 27, 1982. The August 27, 1982 Order approved a series of settlement agreements with varying avoided cost methodologies and directed utilities to file tariffs with the Commission and make their assumptions, data, and the calculation methodology available to the public upon request.

A significant case related to Consumers Energy Company's avoided cost determination involved a PURPA contract between the Midland Cogeneration Venture and Consumers Energy, MPSC Case No. U-8871. The Commission consolidated more than 40 cases to undertake a comprehensive proceeding to consider this contract and many others. The case included a series of 20 Orders from 1987 – 1993 and resulted in many QF contracts with rates based on a proxy coal plant's avoided cost.

On June 10, 2008, the Commission issued an order in another significant case involving MCV and Consumers Energy, Case No. U-15320. This order reduced the capacity charge from the 3.62 cents per kilowatt-hour (kWh) that the Commission had previously approved for cost recovery to 1.014 cents per kWh.[2] Also included in this order, was a provision to change the variable energy charge from a coal-based charge to a natural gas-based charge.

Several legislative acts were passed in Michigan related to PURPA. Act 81 of 1987 (MCL 460.6j, as amended) was enacted to address capacity payments for PURPA contracts, as well as other issues. Act 2 of 1989 (MCL 460.6o, as amended) was enacted to address utility purchases from certain landfill gas and solid waste QFs. The Energy Policy Act of 2005 (PL 109-58; 119 Stat 594) allowed utilities to terminate mandatory purchase obligations if QFs have non-discriminatory access to competitive markets.

Several PURPA contracts were executed and approved by the Commission during this time period, either ex parte or as part of a contested case.

[2] https://mi-psc.force.com/s/filing/a00t0000005pfgwAAA/u153200078

Status of Qualifying Facilities

When PURPA was implemented in 1978, a new class of generating facilities was established. This new class, known as qualifying facilities, would receive special rate and regulatory treatment. FERC has two categories for QFs: qualifying small power production facilities, and qualifying cogeneration facilities. A small power production facility generates 80 MW or less. Its primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. A cogeneration facility sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. Generation facilities must meet FERC requirements in order to be designated as QFs.[3] Changes to PURPA in 2005 require FERC to excuse utilities upon request from the mandatory purchase obligation if the QF has non-discriminatory access to a wholesale electricity market such as MISO. There is a rebuttable presumption that QFs larger than 20 MW meet this requirement. Both Consumers Energy and DTE Electric have requested and received relief from FERC regarding the mandatory purchase obligation from QFs larger than 20 MW.[4]

Michigan QFs

In order to have current, accurate data for this report, the Michigan Public Service Commission (MPSC, or Commission) issued a survey request to rate-regulated utilities in Michigan. The survey asked for information on qualifying facilities. Specifically, each utility

[3] https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp
[4] https://www.ferc.gov/whats-new/comm-meet/2010/041510/E-12.pdf and https://www.ferc.gov/EventCalendar/Files/20120424160511-QM12-3-000.pdf

was asked to provide for each QF: name, technology type, nameplate capacity, contract termination date, and type of contract. This excludes any net-metered facilities.

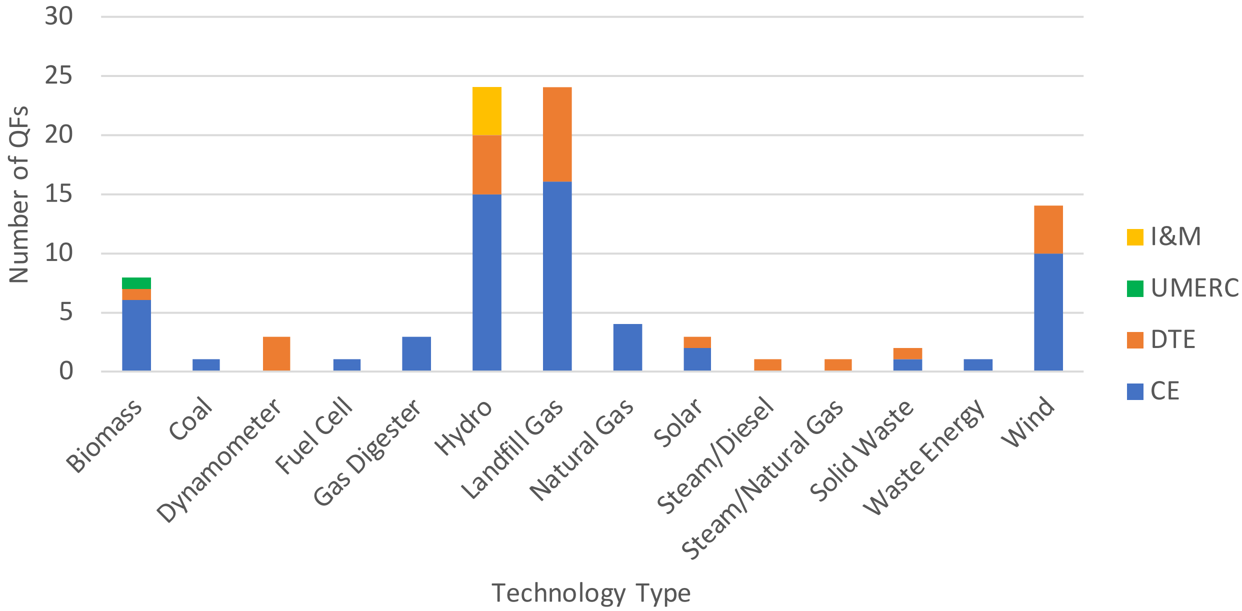
There are eight rate-regulated electric utilities in Michigan (Alpena Power, Consumers Energy, DTE Electric, Indiana Michigan Power, Northern States Power-Wisconsin, Upper Peninsula Power, Upper Michigan Energy Resources Corporation (UMERC), and Wisconsin Electric Power). While Alpena Power Company, Northern States Power Company-Wisconsin, Wisconsin Electric Power Company, and Upper Peninsula Power Company did not report any QFs located in Michigan, the remaining four utilities reported having at least one QF.

Consumers Energy and DTE Electric reported 61 and 24 QFs, respectively. Detailed QF information provided by both companies is summarized in detail below. UMERC has one biomass-fueled QF with a nameplate capacity of 56 MW. Indiana Michigan Power Company (I&M) has four hydro QFs in its Michigan territory with total nameplate capacity of 1.35 MW. Data on QFs participating in the Distributed Generation Program and Consumers Energy's Experimental Advanced Renewable Program (small-scale solar and anaerobic digesters) is presented each year in the Commission's annual Distributed Generation Report.[5]

Figures 1 and 2, below, provide a summary of QF contracts by technology type for rate-regulated utilities in Michigan.

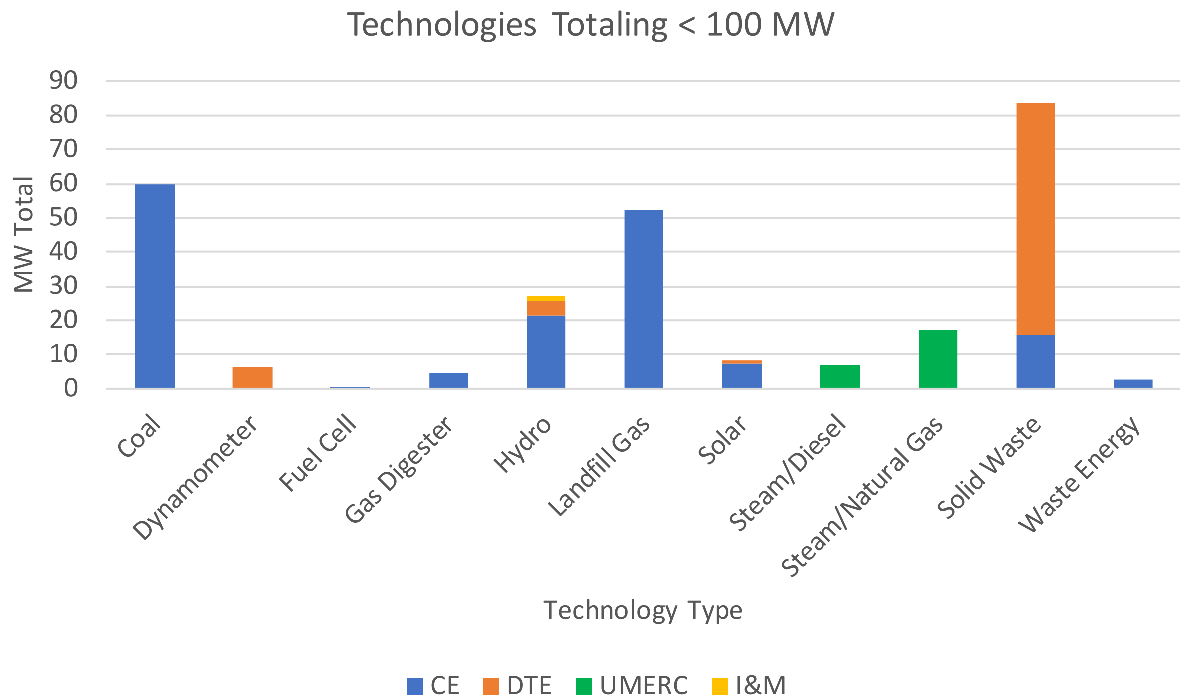
[5] http://www.michigan.gov/documents/mpsc/net_metering_report_2017_2016data_Final_609593_7.pdf

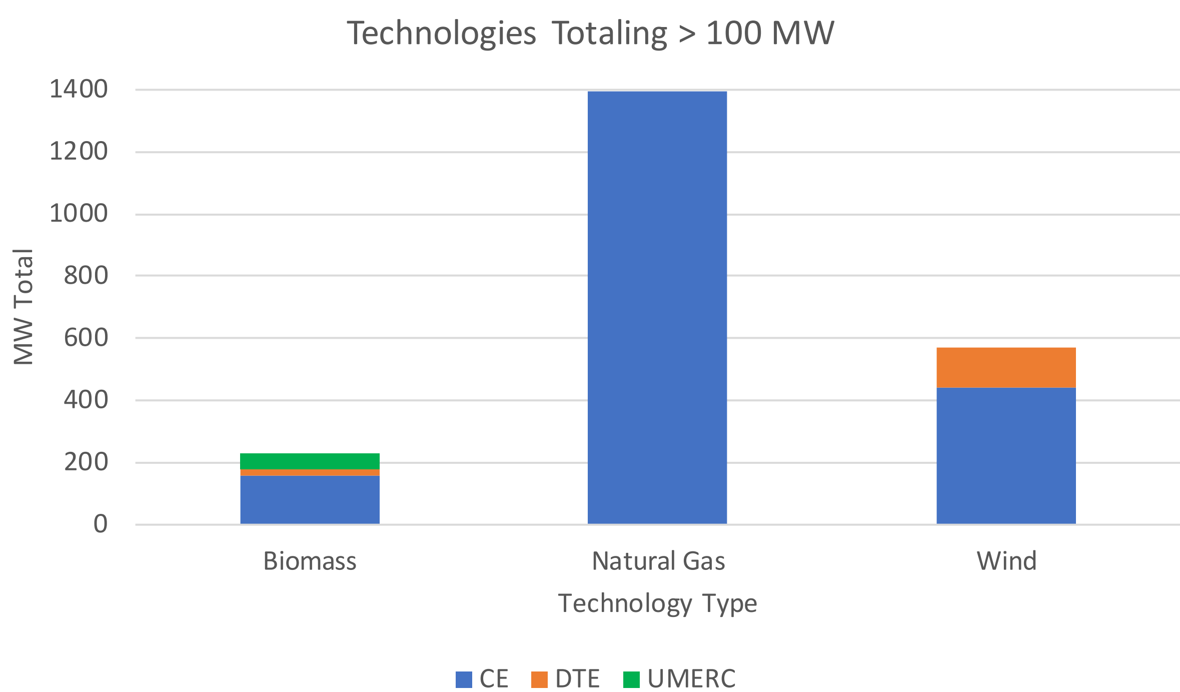
Figure 1: Rate-Regulated Utility QFs by Technology Type, 90 Total QFs



Source: MPSC QF Survey Data Provided by Utilities, March 2018

Figure 2: Rate-Regulated Utility QF Nameplate Electric Generating Capacity by Technology Type, 2,467 MW Total

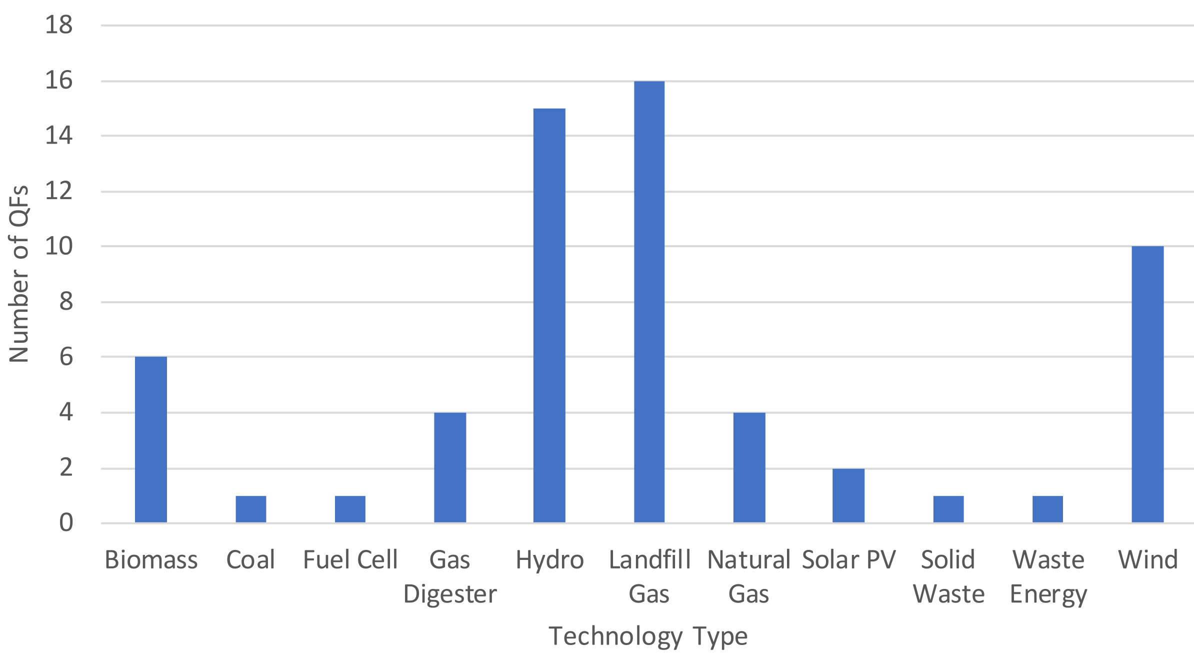




Source: MPSC QF Survey Data Provided by Utilities, March 2018

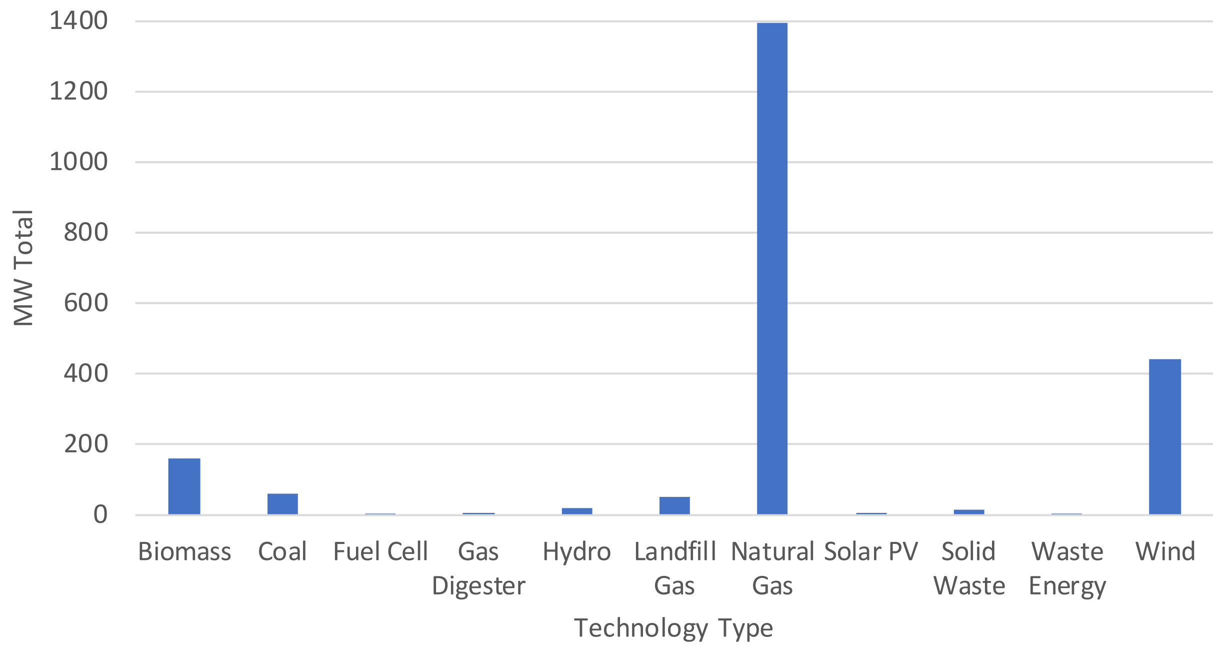
The two largest investor-owned utilities in Michigan are Consumers Energy (CE) and DTE Electric (DTE). CE has 61 QF facilities operating within its territory. Figure 3, below, summarizes CE's qualifying facilities by technology type. These 61 QFs have a total of 2,163 MW of nameplate capacity (excluding net-metering capacity). Figure 4, also below, summarizes this nameplate capacity by technology type.

Figure 3: Consumers QFs by Technology Type, 61 Total QFs



Source: MPSC QF Survey Data Provided by Utilities, March 2018

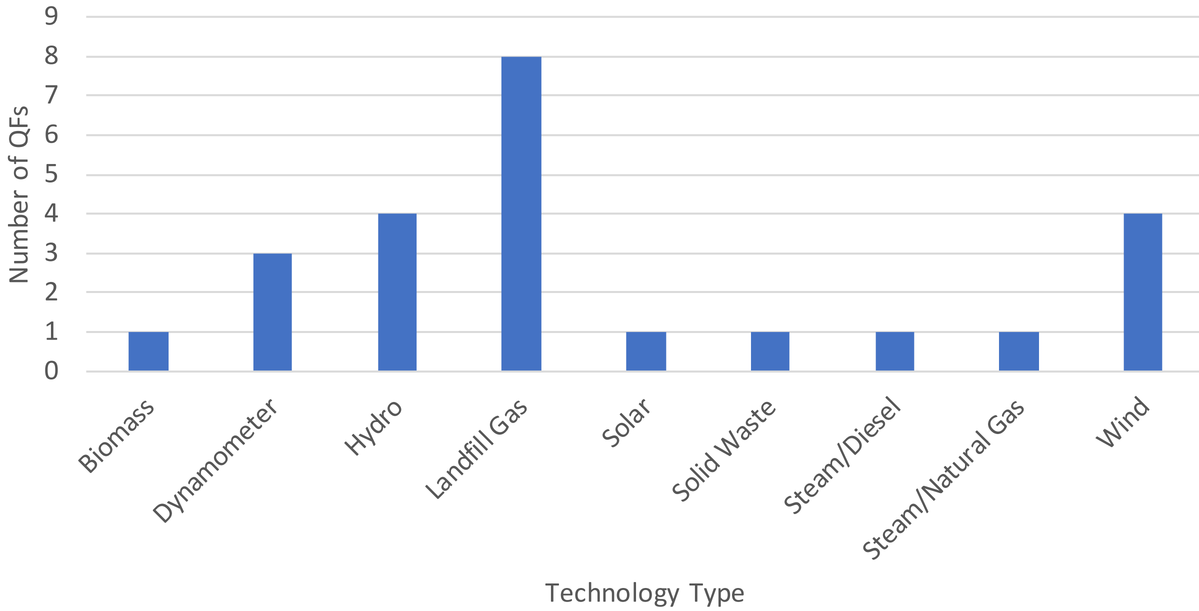
Figure 4: Consumers QF Nameplate Capacity by Technology Type, 2,163 MW Total



Source: MPSC QF Survey Data Provided by Utilities, March 2018

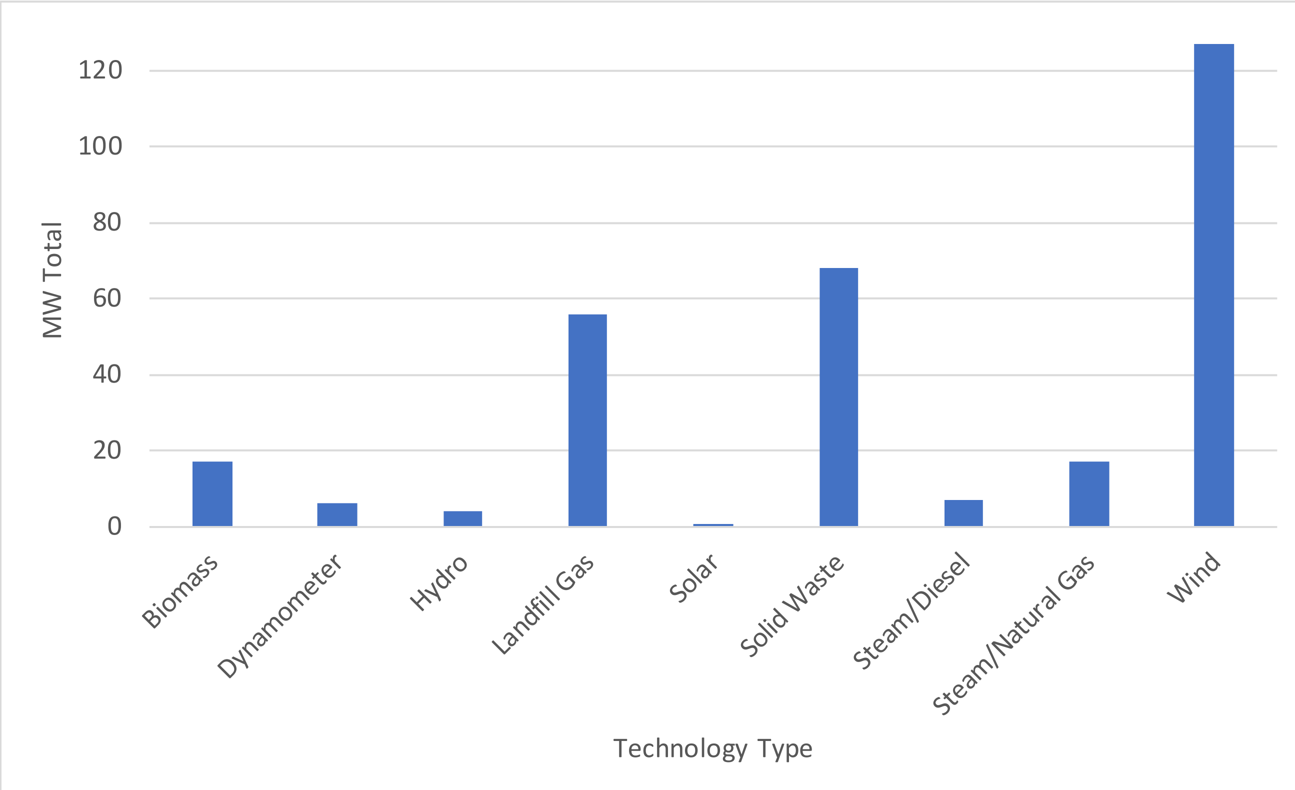
DTE has 24 QF facilities operating within its Michigan territory. Figure 5, below, summarizes DTE's qualifying facilities by technology type. There is a total of 303 MW of nameplate capacity from those 24 facilities. Figure 6, also below, summarizes this nameplate capacity by technology type.

Figure 5: DTE QFs by Technology Type, 24 Total QFs



Source: MPSC QF Survey Data Provided by Utilities, March 2018

Figure 6: DTE QF Nameplate Capacity by Technology Type, 303 MW Total



Source: MPSC QF Survey Data Provided by Utilities, March 2018

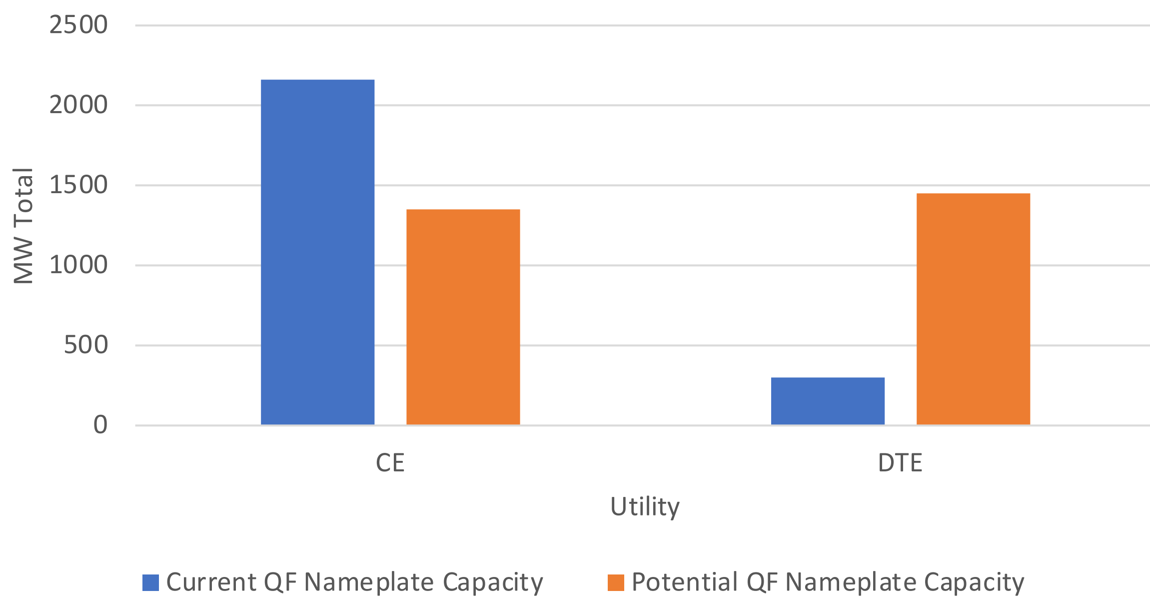
Potential QFs

The Commission has been updating utilities' avoided cost rates for payment to existing (upon contract expiration, as applicable) and any new QFs.[6] Considering this recent activity surrounding PURPA, CE and DTE have experienced an increase in the number of applications for interconnection and requests for PURPA contracts. As of March 2018, CE reported 1,353 MW of projects in its interconnection queue. As of March 2018, DTE reported 1,449 MW of projects in its interconnection queue. While not all projects in a utility's interconnection queue

[6] For background on ongoing Commission proceedings and initial decisions, see the MPSC's PURPA Issue Brief available at: http://www.michigan.gov/documents/mpsc/MPSC_Issue_Brief_--_PURPA_606768_7.pdf

are QFs and some are likely to drop out of the queue for various reasons (interconnection costs, site control and permitting issues, etc.), the size of the interconnection queues indicates a significant uptick in QF development activity. The projects are primarily solar. For the purposes of this report, projects in CE's and DTE's interconnection queues are considered "potential" QFs. Figure 7, below, illustrates a comparison between the existing and potential nameplate capacity of QFs for both CE and DTE.

Figure 7: Comparison of Existing and Potential QF Nameplate Capacity



Source: MPSC QF Survey Data Provided by Utilities, March 2018

Status of Power Purchase Agreements

A power purchase agreement (PPA), as defined by FERC, guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.[7] PPAs are an agreement between a utility and a QF for the sale of energy, capacity, or both. PURPA requires utilities to make a Standard Offer rate available to QFs. The Standard Offer is a tariffed rate paid to QFs through a standard contract with the utility. By law, the Standard Offer must be available to QFs 100 kW and smaller. However, it may be made available to larger QFs. At the time PURPA was first implemented in the early 1980s, the Standard Offer tariff was limited to QFs 100 kW and smaller, which is small enough that an accompanying Standard Offer PPA was most likely not needed and the terms and conditions of service could be included in the Standard Offer tariff.

In Michigan, not all QFs are selling power under a traditional avoided cost PURPA contract. Since the enactment of Michigan's renewable portfolio standard (RPS) in 2008, some utilities, primarily CE and DTE, have contracted for renewable energy to fulfill a portion of RPS requirements. As required by PA 295 of 2008, as amended, RPS contract pricing is in nearly all cases, based upon competitive bidding.

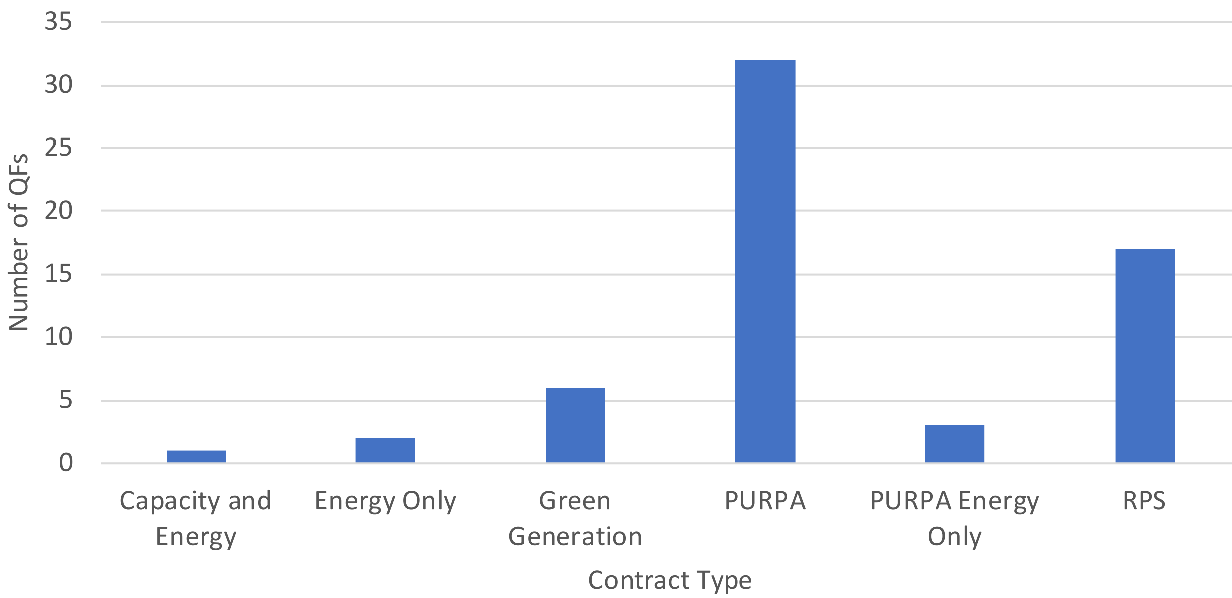
Michigan QF PPAs

As CE and DTE have nearly all of the QF PPAs in Michigan, the report focuses on the status of their contracts. CE has power purchase agreements with each of its 61 QFs. The majority of the PPAs are PURPA contracts for both energy and capacity. CE currently has 32 PURPA contract PPAs. CE also has 17 renewable portfolio standard (RPS) PPAs. These contracts contribute to CE achieving its renewable energy goal for the state of Michigan as Section 35 of 2008 PA 295 provides for utility ownership of four out of five renewable energy credits unless the PPA specifies otherwise. CE has six PPAs that are green generation contracts. There are also three PURPA energy-only contracts, as well as two energy-only PPAs. Finally,

[7] https://www.ferc.gov/market-oversight/guide/glossary.asp#P

CE has one PPA with a QF that is providing both capacity and energy, but not classified as PURPA. This PPA meets the standards of a PURPA contract, however, because it was executed before PURPA was enacted, it is classified as a capacity and energy contract by CE. Figure 8, below, summarizes the types of QF PPAs that CE has in Michigan.

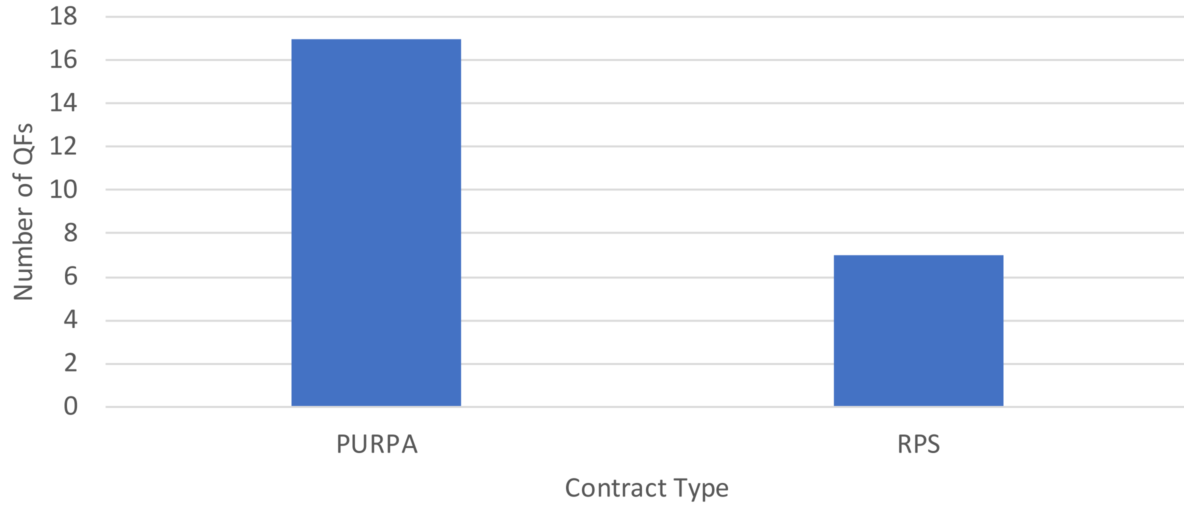
Figure 8: Consumers QF Totals by Contract Type, 61 Total Contracts



Source: MPSC QF Survey Data Provided by Utilities, March 2018

DTE currently has two types of PPAs for its 24 QFs. Seventeen of DTE's QF PPAs are classified as PURPA contracts. The other seven PPAs are classified as RPS contracts. Figure 9, below, summarizes the PPAs for DTE.

Figure 9: DTE QF Totals by Contract Type, 24 Total Contracts

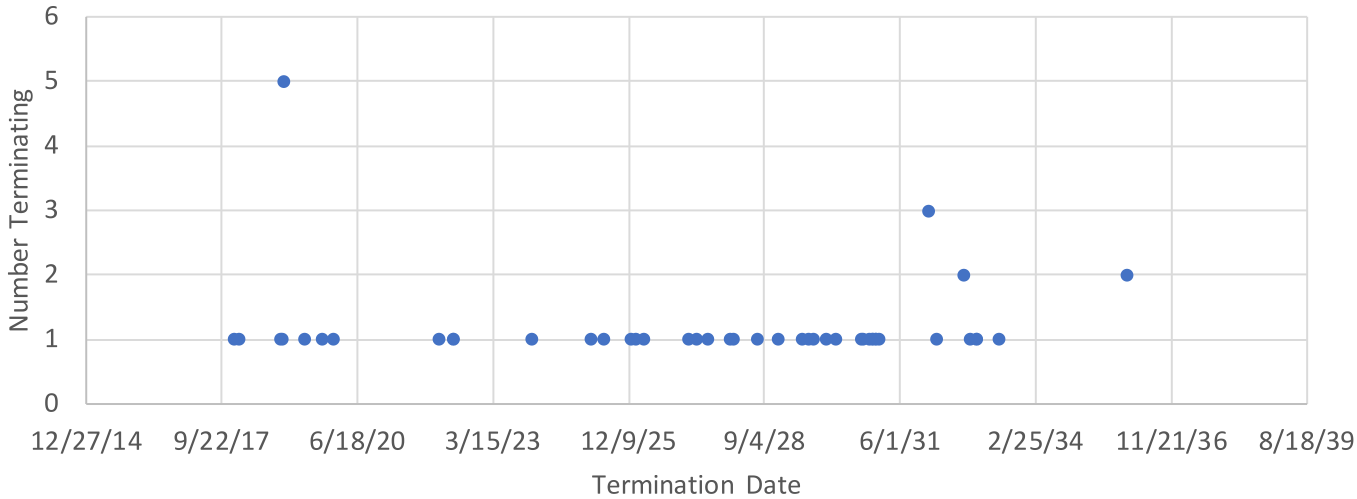


Source: MPSC QF Survey Data Provided by Utilities, March 2018

For the other investor-owned utilities in Michigan, UMERC has one QF with a customer generating system (CGS) large tariff PPA. I&M has four QFs with cogeneration PPAs. Alpena Power Company, Northern States Power Company-Wisconsin, Wisconsin Electric Power Company, and Upper Peninsula Power Company did not report any PPAs in Michigan.

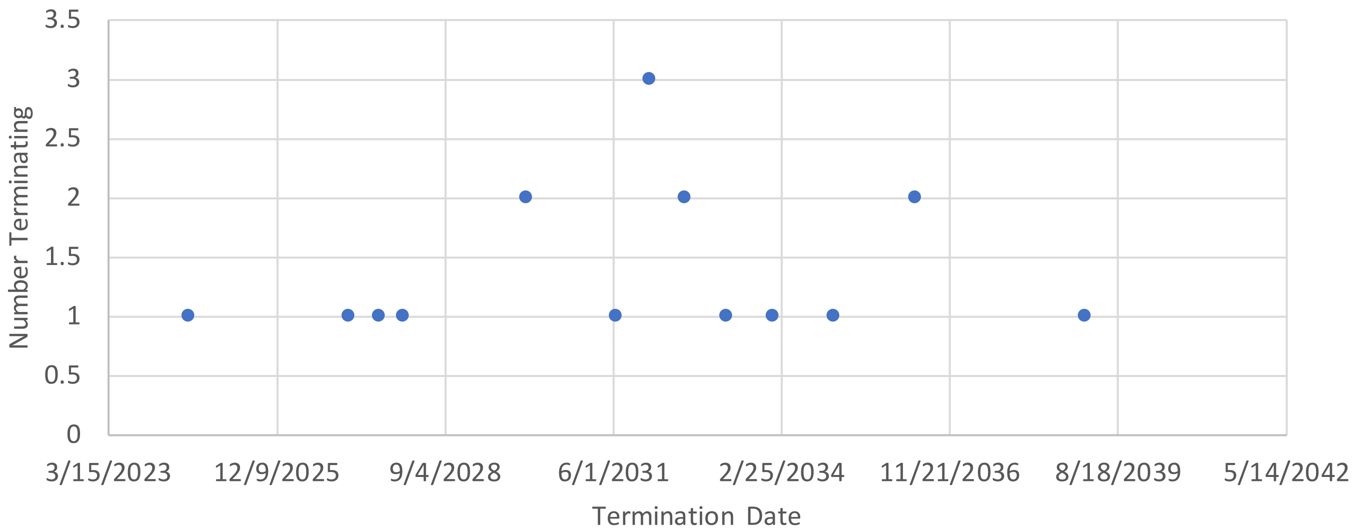
Many of the current PPAs are long-term contracts. CE has several long-term PPAs that have recently expired or will expire in the near future. Many of the other CE PPAs have terms that end in the 2030s. DTE has fewer long-term PPAs, and the first expiration date is in 2024. Similar to CE, DTE has many PPAs with terms ending in the 2030s. UMERC has one PPA that will retain tariff service until it expires. I&M has four PPAs that are on-going with six month's written notice to the other party of the intention to discontinue service under the terms of the contract. Figure 10, below, shows contract termination dates for CE PPAs. Figure 11, also below, shows contract termination dates for DTE PPAs.

Figure 10: Consumers QF Contract Termination Dates[8]



Source: MPSC QF Survey Data Provided by Utilities, March 2018

Figure 11: DTE QF Contract Termination Dates[9]

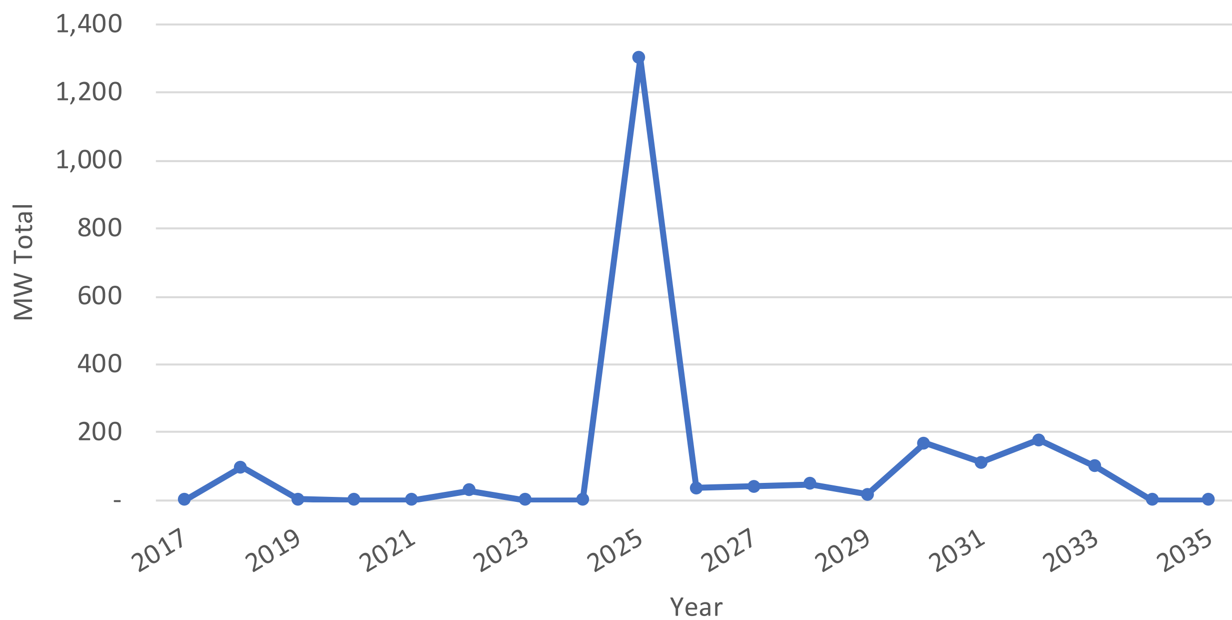


Source: MPSC QF Survey Data Provided by Utilities, March 2018

[8] CE chart does not include four PPAs on month-to-month contracts, three PPAs with contracts TBD, two PPAs with various contract terms, and one PPA with a year-to-year contract.
[9] DTE chart does not include six evergreen PPA contracts.

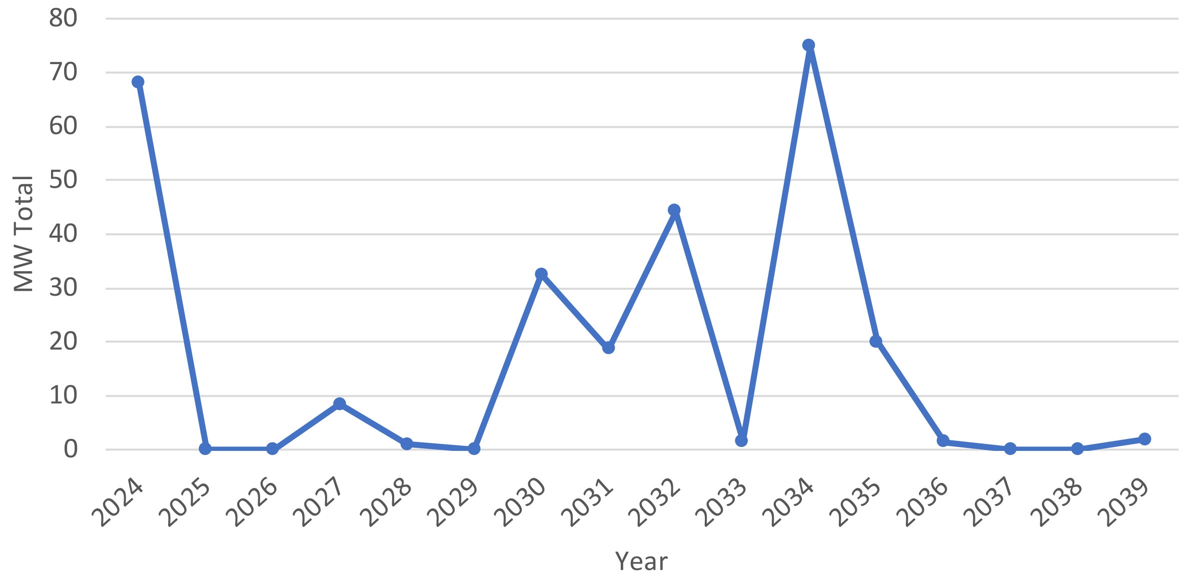
Figures 12 and 13, below, illustrate the generation capacity at risk each year as the PPAs expire. Unless the contract is extended, CE will experience a large decline in its PURPA capacity under contract (1,300 MW) in 2025. DTE will not experience such a large loss of QF capacity in a single year. The two years with the highest amount of capacity with expiring contracts for DTE are 2024 with 68 MW expiring and 2034 with 75 MW.

Figure 12: CE QF Generation Termination by Year



Source: MPSC QF Survey Data Provided by Utilities, March 2018

Figure 13: DTE QF Generation Termination by Year



Source: MPSC QF Survey Data Provided by Utilities, March 2018

Commission PURPA Activities

Interconnection

The Commission's Electric Interconnection & Net Metering Standards govern the interconnection process for distribution-level interconnections.[10] The trend showing an increase in interconnection requests experienced by many utilities across the country can be seen in Michigan as well. Advances in distributed generation technology (i.e., inverters), and updates to Institute of Electrical and Electronics Engineers 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems all point to the need to update the Commission's interconnection rules. Updating the Commission's interconnection rules is part of the

[10] http://dmbinternet.state.mi.us/DMB/ORRDocs/AdminCode/825_10791_AdminCode.pdf

Commission's strategic plan for 2017-2019. As a matter of providing some transparency into CE's and DTE's interconnection queues, CE has made a public listing of projects in its interconnection queue available on its website[11] and this topic is being addressed in DTE's pending rate case proceeding, Case No. U-18255.

PURPA Technical Advisory Committee

The Commission issued an order on October 27, 2015 in Case No. U-17973 directing the Electric Reliability Division[12] to form a Technical Advisory Committee (TAC) to assess the continuing appropriateness of its current regulatory implementation regarding PURPA. The order was issued due to some existing PURPA contracts expiring and potential new QFs inquiring about avoided cost rates and other factors. The order directed the PURPA TAC to issue a report by April 8, 2016. On that date, The PURPA Technical Advisory Committee Report on the Continued Appropriateness of the Commission's Implementation of PURPA (PURPA TAC Report) was filed.

The PURPA TAC Report summarized the Staff's findings from the five meetings of the PURPA TAC. It presented Staff's proposed administrative process for establishing a new avoided cost calculation methodology. Additionally, Staff proposed that rate-regulated utilities were to update avoided cost calculations in contested cases biennially. For the avoided cost calculation, Staff recommended a hybrid proxy plant method where the avoided capacity cost would be based on the capital cost of a natural gas combustion turbine plant (NGCT). Avoided energy cost would be based on the forecasted cost of operating a natural gas combined cycle

[11] Consumers Energy's interconnection queue: https://www.consumersenergy.com/-/media/CE/Documents/renewables/generator-interconnection/generator-interconnection-status-report.ashx?la=en&hash=46D1A2D42B28823284458573923DD81477569697
[12] The Electric Reliability Division was reclassified as the Energy Resources Division effective April 8, 2018.

plant (NGCC), or actual or forecasted MISO locational marginal prices. Staff proposed that the QF can select the energy rate option that most effectively suits its needs. Staff also introduced a fixed investment cost attributable to energy (ICE) as a component of the avoided energy payment to QFs. The ICE component is added to account for the fixed-cost differences between a NGCT and a NGCC. Capacity needs would be forecasted for a 10-year planning horizon, as outlined in §292.302 (b)(2) of the PURPA regulations.

In the report, Staff recommended that the renewable energy credits (RECs) generated by the QF stay with the QF. Sale of RECs could be negotiated. Transmission costs and line loss mitigation with respect to the avoided cost calculation was recommended for case-by-case evaluation.

Staff also had recommendations for the Standard Offer tariff and rate. Staff supported a standard rate for existing QFs and QFs that are 5 MW and smaller. While past PURPA contracts had been long term, with some spanning over 30 years, Staff recommended a contract term that spans the shorter of either the QF financing period or 17.5 years for new QFs.

A draft version of the PURPA TAC report was circulated to the workgroup participants for comments. Staff reviewed the comments and incorporated them into the final version of the report where appropriate. All comments received were attached to the final report.

Commission PURPA Proceedings

After the PURPA TAC Report was issued, the Commission issued an Order on May 3, 2016, in Case Nos. U-18089 et al. directing rate regulated utilities to file their respective avoided cost information in their assigned dockets. The utilities were directed to calculate avoided cost using: 1) the hybrid proxy plant method proposed in the PURPA report; 2) the transfer price method developed under 2008 PA 295; 3) another method, if any, that the company wishes to propose; and 4) proposed standard rate tariffs, including applicable design capacity.[13] The status of these utility PURPA proceedings are discussed further below.

Avoided Cost and Standard Offer Tariff

PA 341 also directs the Commission to address avoided cost and a Standard Offer tariff. Section 6v(4) states that the Commission shall "[e]stablish a schedule of avoided cost prices updates for each electric utility."[14] There are several different methods for calculating avoided costs. The state commission (or, as applicable, the non-regulated utility) determines the method for calculating avoided costs. The chosen method must fit the definition of avoided cost and be non-discriminatory. The avoided cost methodology must also be consistent with FERC rules.[15]

PA 341 Section 6v(4) also states that the Commission shall "[r]equire electric utilities to publish on their websites template contracts for power purchase agreements for qualifying facilities of less than 3 megawatts that need not include terms for either price or duration of the contract. The terms of a template contract published under this subsection are not binding on either an electric utility or a qualifying facility and may be negotiated and altered upon agreement between an electric utility and a qualifying facility."[14] PURPA requires each utility to have standard rates for purchases from QFs with project design capacities of 100 kW or less. There may be standard rates for purchases from QFs with project design capacities greater than 100 kW. The Commission is considering parameters of avoided cost, Standard Offer tariffs, and PPAs as part of the PURPA proceedings which are described in the next section of this report.

---

[13] Order U-18089 et al. http://www.michigan.gov/documents/mpsc/u-18089etal_5_3_2016_565229_7.pdf
[14] MCL 460.6v(4)
[15] PURPA Title II Compliance Manual
http://www.eei.org/issuesandpolicy/stateregulation/Documents/PURPA_Title_II_Manual.pdf

Ongoing PURPA Proceedings

Alpena Power Company

The Alpena Power Company (Alpena) filed an Application Providing Avoided Cost Methodology in Case No. U-18089 on June 17, 2016. Alpena is an investor-owned utility in Michigan with no company-owned generation facilities. Alpena purchases 100% of its power, with most of the purchased power supplied by CE under a contract that expires in 2024.[16]

After a prehearing conference and one round of testimony, Alpena filed a Settlement Agreement with the Commission on June 5, 2017 and an Amended Settlement Agreement on June 7, 2017. The amended settlement agreement states that until January 1, 2025, Alpena's avoided cost is the cost that Alpena pays to CE for supplemental power under a 30-year contract ending December 31, 2024. On January 1, 2025, Alpena's avoided cost will be the rates for capacity and energy stated in the Standard Offer tariff.

The amended settlement agreement also states that the Commission will review Alpena's avoided cost on a biennial basis. Alpena's Standard Offer tariff size cap will be 1 MW for the first two-year term prior to the first biennial review. Line loss savings will be evaluated on a case-by-case basis. All RECs will remain the property of the QF. The amended settlement agreement also included Alpena's proposed Standard Offer tariff sheets. Because Alpena purchases most of its power from CE, the settlement of this case is awaiting a final Commission order in U-18090 (CE Avoided Cost Proceeding).

[16] Under its Consumers Energy contract, Alpena purchases two types of power, Firm and Supplemental. Alpena purchases 35 Megawatts of Firm power from Consumers Energy on a continuous basis, measured and billed in kilowatt-hours. In addition to those purchases, Alpena also, on an as needed basis throughout each month, purchases Supplemental Power from Consumers to meet all energy demands above each month's purchase of its Firm Power purchase requirement.

Consumers Energy Company

Consumers Energy Company (CE) filed an Application Providing Avoided Cost Methodology in Case No. U-18090 on June 17, 2016. On May 31, 2017, an order was issued in this case approving Staff's hybrid-proxy plant method as the most appropriate method for calculating CE's avoided capacity and energy costs. A 10-year, capacity planning horizon was also determined to be reasonable. The design capacity for the Standard Offer tariff was set at 2 MW, with term lengths to be set at five, 10, 15, or 20 years at the QF's option. This order also determined that any RECs generated would belong to the QF under the Standard Offer and PPAs. The Commission committed to reviewing PURPA rates every two years.

The May 2017 order remanded the case so that parties could file testimony addressing several inputs for calculating the avoided capacity cost using a natural gas combustion turbine unit and avoided energy cost using a natural gas combined cycle as proxy plants.

On July 31, 2017, a further order was issued in this case. This order provided guidance regarding inputs to the NGCT model, as well as an appropriate heat rate and assumed capacity factor for the NGCC proxy unit. However, the case was remanded a second time to allow parties to file testimony and exhibits supporting forecasted natural gas prices, including a levelized energy payment, a proposed energy payment schedule, and final Standard Offer tariff.

On November 21, 2017, the Commission issued a final order in this case. The order determined that the NGCT inputs from CE were appropriate and set the avoided capacity cost at $140,505/ZRC-year. The order approved the use of regional EIA Forecasted Natural Gas Delivered Price. The order also determined that CE's inputs for NGCC fixed and variable cost should be included in calculations for fixed and variable operations and maintenance costs. The order also stated that because ICE is part of energy, the 2.37% line loss factor should be added to the sum of the avoided energy cost plus ICE.

After the final order was issued in this case, CE filed a Petition for Rehearing and Clarification on December 20, 2017. The Company also filed a Motion to Stay Capacity Purchase Obligation the same day. On December 20, 2017, CE also filed an Application to Reset Avoided Capacity Costs in Case No. U-18491. The Company submitted testimony that its capacity need had changed from what it filed in Case No. U-18090 and that it no longer had need for new capacity over the 10-year planning horizon. With no capacity need, CE stated that avoided capacity cost should be set at the MISO Planning Resource Auction (PRA) price for all new PURPA QF offers to sell capacity to the Company.

The same day, December 20, 2017, the Independent Power Producers Coalition of Michigan also filed a Petition for Rehearing in this case. The Commission also issued an order in this case on December 20, 2017. The order suspended implementation of avoided costs for capacity and energy until petitions for rehearing could be addressed. The order also suspended the Standard Offer tariff for CE.

After responses from the parties to this case, the Commission issued a subsequent order in this case on February 22, 2018. This order grants, in part, CE's Petition for Rehearing and reopens the U-18090 proceeding. CE was directed to file its final Standard Offer tariff and draft PPA by March 1, 2018. In the February 22 order, the Commission found that "…to allay any concerns that the company may find itself paying the full avoided capacity payment and becoming awash in unneeded QF capacity, the Commission finds it appropriate to limit payment of the full avoided capacity cost to the first 150 MWs in the queue." The order established a hearing date on March 13, 2018 and directed the Administrative Law Judge to complete a briefing by July 16, 2018 with an optional extension up to 30 days for good cause.

DTE Electric

DTE Electric (DTE) filed an Application Providing Avoided Cost Methodology in Case No. U-18091 on June 17, 2016. The Commission issued an order on July 31, 2017. This order determined that the most appropriate method for calculating DTE's avoided cost is Staff's hybrid proxy plant method. The Commission also agreed with Staff's investment cost attributable to energy (ICE) payment added to the energy cost to account for the difference between capital costs of a NGCT and a NGCC. A 10-year capacity planning horizon was found to be appropriate, as was a biennial PURPA review. The order also directed DTE to renew existing QF contracts at the full avoided cost rate.

The Commission order further addressed issues with the Standard Offer tariff. It determined that QFs should be able to choose five, 10, 15, or 20-year contract terms. The design capacity for the Standard Offer tariff was set at 2 MW for DTE. The Commission also determined that RECs generated by the QFs should remain assets of the QFs. This July 31, 2017 Order also remanded the case for further review. Parties were instructed to file proposed inputs to calculate avoided capacity cost based on a NGCT unit and avoided energy cost based on a NGCC unit and the ICE adder calculation by August 15, 2017. Parties were also instructed to file a proposed Standard Offer tariff with cost forecasts. This case is awaiting a Commission order.

Indiana Michigan Power Company

Indiana Michigan Power Company (I&M) filed an Application Providing Avoided Cost Methodology in Case No. U-18092 on June 30, 2016. I&M is a utility organized and existing in Indiana and authorized to do business in Michigan. I&M currently uses avoided cost data based on estimates of the fixed costs of a combustion turbine and I&M's avoided cost of energy. These three-year average avoided cost calculations support current standard offer rates in I&M's cogeneration tariff. The current methodology is approved by the Indiana Utility Regulatory Commission. This case is awaiting a Commission order.

Northern States Power Company-Wisconsin

Northern States Power Company-Wisconsin (NSP-W) filed an Application Providing Avoided Cost Methodology in Case No. U-18093 on June 30, 2016. NSP-W is an investor-owned utility that generates, transmits, distributes, and sells electric energy. NSP-W utilizes a planning mechanism called Upper Midwest Resource Plan. This plan is filed with the Minnesota Public Utilities Commission and is updated every two years. The plan includes a five-year action plan and a 15-year planning period. NSP-W currently has no QFs in its Michigan service territory. The case is awaiting a Commission order.

Upper Peninsula Power Company

Upper Peninsula Power Company (UPPCo) filed an Application Providing Avoided Cost Methodology in Case No. U-18094 on June 17, 2016. UPPCo is a small utility located in Michigan's Upper Peninsula, and as such, constructing generation assets would likely not be the most effective way to fulfill the capacity and energy needs of its customers. The company has a contract for capacity through May 31, 2020. The Commission issued an order in this case on

September 28, 2017 finding that until May 31, 2020, UPPCo's avoided capacity cost should be set at its capacity contract price at the time that the PURPA contract is entered into, with an adjustment for effective load carrying capability (ELCC)[17] applied. After May 2020, the appropriate method for calculating avoided capacity cost will be addressed at UPPCo's next PURPA review. The Commission directed UPPCo to file its PURPA review application by February 1, 2019. A 10-year planning horizon for capacity requirements was found to be appropriate for UPPCo.

The order also states that a QF may opt for an avoided energy cost based either on locational marginal price (LMP) at the time the energy is delivered or on UPPCo's forecasted LMP. For LMP to have forecasts for 20 years in the record, the case was remanded, and the parties were directed to file LMP forecasts by October 16, 2017.

The Standard Offer tariff, as addressed in the order, shall be available for a term of five, 10, 15, or 20 years at the QF's discretion. A 1 MW cap was found to be reasonable given the size and limited capacity needs of UPPCo. As part of the remand to reopen these proceedings, parties were directed to file updated Standard Offer tariffs including LMP energy rates for five, 10, 15, and 20 years and line losses by voltage level.

After testimony was filed in response to the September 2017 remand order, a Settlement Agreement was filed on December 15, 2017. The Settlement Agreement included an LMP forecast for five, 10, 15, and 20 years, as well as a Standard Offer tariff from UPPCo. The Commission issued an order on January 23, 2018 approving the Settlement Agreement.

[17] ELCC is the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors for load not being served.

Wisconsin Electric Power Company and Wisconsin Public Service Corporation/Upper Michigan Energy Resources Corporation

Wisconsin Electric Power Company (WEPCo) and Wisconsin Public Service Corporation (WPS) issued Applications Providing Avoided Cost Methodology in Case Nos. U-18096 and U-18095 on June 30, 2016. The two cases were consolidated on December 7, 2016. WEPCo filed two proposed customer generation tariffs in its Application to reflect standard rates for purchasing from QFs. WPS filed its standard rates for purchasing from QFs within its three parallel generation tariffs. The WPS Application also referenced the formation of a new utility, Upper Michigan Energy Resources Corporation (UMERC) pending in Case No. U-18061.

After the formation of UMERC in January 2017, all the Michigan customers from WEPCo and WPS will be transferred to UMERC, with the exception of the Tilden Mining Company L.C. (Tilden). Tilden will remain a customer of WEPCo under a special contract approved by the Commission, in Case No. U-17862 on April 23, 2015, until UMERC places new generation in service. UMERC will be a small utility and will contract power from WEPCo and WPS under full requirements PPAs. As described in Case No. U-18224, a Certificate of Necessity (CON) was filed for UMERC to construct two reciprocating internal combustion engine (RICE) electric generation facilities in Michigan's Upper Peninsula (UP). The PPAs between UMERC and WEPCo and WPS will remain in effect until the RICE units become operational. With these RICE units in operation, UMERC will have excess generation.

Because it will only serve a single customer (Tilden) until 2019, WEPCo has submitted testimony that it is unnecessary to establish an avoided cost. Staff supports this view and testified that it would be administratively inefficient to establish an avoided cost for WEPCo for such a short time period. The cases are awaiting Commission orders.

Supplemental, Backup, Maintenance, and Interruptible Power (Standby Service)

There has been increasing interest in rates for utility standby service. Standby service is a benefit provided by the utility that makes energy and capacity available to the customer in the event that a customer's generator is unable to operate. Standby rates are paid by retail customers who have on-site electric generating facilities and use the utility for back-up service. PURPA requires utilities to provide standby service to QFs on a non-discriminatory basis. In an order issued on November 2015, the Commission directed Staff to establish the Standby Rate Working Group (SRWG) to review current standby tariffs and develop recommendations for improvements to these tariffs. The SRWG met six times in 2016 with participation from utilities, current and future standby customers, and Commission Staff. The meetings included presentations and discussions. Comments were also accepted on drafts of each report before being issued by the SRWG.

The first report was issued on August 19, 2016.[18] The primary focus of that report was solar generation. The report outlined the main rate components of standby tariffs and summarized the tariffs used by CE and DTE. "The preliminary analysis completed by Staff as part of the SRWG activities indicates that it is not necessary for non-residential, self-generation solar projects to take service under a standby service tariff provided the normal service tariff incorporates a delivery demand charge and either a power supply demand charge or accurate time of use rates."[19] Staff indicated that a supplemental report was needed to address non-

[18] https://mi-psc.force.com/s/filing/a00t0000005pVNCAA2/u177350392
[19] Standby Rate Working Group (SRWG) Report https://mi-psc.force.com/s/filing/a00t0000005pVNCAA2/u177350392

intermittent standby service tariff design and to update its solar standby recommendations if needed.

The second report from the SRWG was issued in June of 2017.[20] The supplemental report focused on non-intermittent standby service tariff design. The report also presented Staff's recommendations on standby service tariffs for both combined heat and power (CHP) and solar self-generation. The SRWG issued a list of seven recommendations for standby service tariffs. These recommendations can be found in the Standby Rate Working Group Supplemental Report.[21]

Standby rates have been traditionally reviewed in rate cases. In the most recent rate cases of CE and DTE, standby rates have been included as a rate case issue.[22] PURPA includes a provision requiring utilities to provide standby service as follows:

> (c) Rates for sales of back-up and maintenance power. The rate for sales of back-up power or maintenance power
>
> (1) Shall not be based upon an assumption (Unless supported by factual data) that forced outages or other reductions in the electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both: and
>
> (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.[23]

[20] http://www.michigan.gov/documents/mpsc/SRWG_Supplemental_2017_Report_576352_7.pdf
[21] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UMMSAA4
[22] CE's Rate Case No. U-18322 https://mi-psc.force.com/s/global-search/18322 had a final order issued on March 29, 2018. DTE's Rate Case No. U-18255 https://mi-psc.force.com/s/global-search/18255 is awaiting an order.
[23] 18 CFR 292.305

Section 6v of PA 341 also directs the Commission to "[r]equire that any prices charged by an electric utility for maintenance power, backup power, interruptible power, and supplementary power and all other such services are cost-based and just and reasonable."[24] The Commission has determined the appropriate forum for addressing this issue from a procedural standpoint in Case No. U-18090 in its May 31, 2017 order. The Commission found that the "other rate elements of PURPA, namely, maintenance, backup, interruptible, and supplementary power, and other services, are being addressed in other proceedings and need not be addressed here."[25]

Case No. U-20095

To address other issues that have arisen in the PURPA proceedings, the Commission issued an order on February 22, 2018 opening a docket in Case No. U-20095. The Commission requested comments regarding the determination of capacity need, the process for resetting avoided capacity cost, and the criteria for determining whether a legally enforceable obligation has been created. The order also included specific questions for commenters to consider. Comments were due March 19, 2018.

Proposed PURPA Modernization Act of 2017

On November 29, 2017, Representative Tim Walberg (R-MI) introduced H.R. 4476 – PURPA Modernization Act of 2017 to "modernize the Public Utility Regulatory Policies Act of 1978."[26] The bill intends to amend PURPA in three main areas. First, the bill would amend the method for determining if facilities are considered to be located at the same site. By converting

[24] MCL 460.6v(4)
[25] May 31, 2017 order in Case No. U-18090 https://mi-psc.force.com/s/filing/a00t0000005ppT3AAI/u180900162
[26] H. R. 4476 https://www.congress.gov/bill/115th-congress/house-bill/4476/text

the "one-mile" rule into a rebuttable presumption, the PURPA Modernization Act of 2017 aims to ensure that two or more facilities located more than one mile apart are independent. The "one-mile" rule was implemented to avoid gaming of the size limitations of QFs, particularly in the case of wind generators, by requiring generators to be located more than one mile apart.

Next, the bill seeks to amend PURPA by lowering the 20 MW threshold mandatory purchase obligation to reflect an increase in competition in electric markets since PURPA was enacted in 1978. The amendment would state that small QFs with generation capacity of 2.5 MW or greater would have nondiscriminatory access to wholesale markets and, therefore, would no longer be subject to the mandatory purchase obligation described in PURPA.

Finally, the PURPA Modernization Act of 2017 would amend PURPA by empowering state public utility commissions to waive mandatory purchase obligations on a case-by-case basis. The bill states that state or local determination can be made if a utility has demonstrated that additional power is not needed to meet the electricity needs of its customers. A utility can establish that it has no need to purchase additional power through an integrated resource plan and by conducting a competitive resource procurement process for long-term energy resources.

The PURPA Modernization Act of 2017 was introduced as H.R. 4476 in the House of Representatives on November 29, 2017. That same day, it was referred to the House Committee on Energy and Commerce. On December 1, 2017, the bill was referred to the Subcommittee on Energy.

Conclusion

The Commission appreciates the electric utilities providing the QF data needed to prepare this first report issued pursuant to Act 341, Section 6v. PURPA-related activities are in progress at the Commission related to QF interconnection with the utility, establishing updated avoided costs and standard offer tariff parameters, and reviewing standby service rates. A process to update the Commission's administrative rules governing electric utility interconnection is expected to begin shortly. The Commission looks forward to continuing its efforts related to PURPA implementation and providing its next report by April 20, 2020.