Guidehouse

Memorandum

To: Roger Doherty, Lynn Beck, Katie Smith, Michigan Public Service Commission (MPSC)

From: Debyani Ghosh, Neil Curtis, Stu Slote, Guidehouse

Date: 3/22/2021

Re: MI 2021 Demand Response Potential Study Global Inputs Summary

This memo describes the approach used to develop market characterization data for assessing Demand Response (DR) Potential. It presents the market segmentation approach and the data used to develop baseline customer count and peak demand projections, which forms the basis for estimating both electric and gas DR potential estimates. The market characterization for DR potential assessment primarily draws on data obtained from the utilities. Guidehouse used secondary data sources such as EIA, FERC Form 1, and the U.S. Census Bureau to fill in data gaps, where applicable.

In addition to the DR-specific baseline count and peak demand projections by customer segment, the following market characterization inputs for the DR analysis overlap with those developed for the energy waste reduction (EWR) study:[1]

- Residential Building Stock
- Electric Demand Avoided Costs
- Gas Avoided Costs
- Discount Rates
- Line Losses
- Inflation

Inputs specific to the DR study are documented below. Please refer to the “MI 2021 Statewide EWR Potential Study Global Data Summary” memo for information related to the common items listed above.

The accompanying “MI_2021_DR Global Data Summary” excel file presents the DR market characterization data.

[1] These inputs are common for EWR and DR and are included in the *MI 2021 EWR Potential Study Global Inputs Summary* Memo.

Customer Segmentation

For the Residential sector, segmentation to disaggregate sector-level data into dwelling type and income level segments was developed as part of the EWR market characterization, and was directly used in the DR baseline development for both electric and gas. These splits were developed using statewide census data on the fraction of housing types (single vs. multi-family) and percentage of income eligible customers (percent of households below 200% of the federal poverty line).

For the electric C&I sector segmentation, disaggregated peak data at the rate code level was mapped to customer count data by rate code or tariff type using utility data or data from FERC Form 1. Then, the average per customer peak demand was calculated for each rate code, which was then used to assign each C&I rate to a segment based on the demand cutoffs shown in Table 1**.** In cases where utility-specific data was unavailable to disaggregate annual energy sales by rate code or C&I Segment, disaggregation factors from other similar utilities were applied.

Table 1. Demand Cutoffs for C&I Segments

C&I Segment	**Demand Cutoffs**
Small C&I	< 30 kW
Medium C&I	30-200 kW
Large C&I	201-1000 kW
Extra Large C&I	> 1000 kW

Like the EWR gas sales forecast, the gas C&I sector segmentation was defined to align the Small C&I and Large C&I segments with DTE's GS-1 and GS-2 gas rate schedules. These schedules have an implicit break-even point of 14,000 therms or $49,300 in gas energy costs per year, and were applied to all other utilities. DTE-provided data on sales and customer counts under each rate code were used to calculate the proportion of the C&I sector peak and number of customers to allocate to the Small C&I and Large C&I segments. The Medium C&I and Extra-Large C&I segments were not used for gas market characterization.

Baseline Customer Count and Peak Demand Projections

Table 2 summarizes the input data sources and the approach used to develop customer count and peak demand projections over 2022-2040, further described below. 2019 is the base year for the analysis[2].

[2] 2019 is the base year as it is the latest year for which full count and peak demand data was available. It aligns with the base year consideration for the EWR analysis.

Table 2. Customer Count and Electric Baseline Peak Approach Summary by Utility

Utility	Data Source			Methodology				
	Customer count forecast	Electric Sales Forecast	Load Factor	Load Factor Development Approach	Summer Months	Winter Months	Residential Segment Disaggregation Approach	C&I Segment Disaggregation Approach
Alpena	Utility request 2021-2040 by rate schedules	Utility request 2021-2040 Rate Schedules	2017 8760	Peak hours from 8760	June - September	November - March	Applied residence type and income splits based on Census data	Calculated C&I coincident peak demand per customer
Consumers	Utility request 2021-2040	Utility request 2021-2040	2017-2019 8760	Utility 12 CP by rate code.	June - September	November - March	Same as above	Same as above
DTE	FERC Form 1 Data for 2019	Utility request 2021-2040	DTE 8760s by rate code	8760 CP mapped to Form 1 data	June - September	October - May	Same as above	Same as above
I&M	Utility request 2021-2040	Utility request 2021-2040	2021 8760s by Sector	Peak demand per sector from 2021 8760 forecast. Applied C&I segment splits from Consumers	May - September	October - April	Same as above	Used average C&I sales and peak breakdowns from other LP utilities.
UMERC	Utility request 2021-2040	Utility request 2021-2040	2017 WEPCo 8760 by rate code	Peak hours from rate-code level 8760	May - October	November - April	Same as above	Calculated C&I coincident peak demand per customer
UPPCO	FERC Form 1 Data for 2019	Utility request 2021-2040	DTE 8760s	Used same Res and Com LF as DTE 8760s	June - September	October - May	Same as above	Same as above
NSP	EIA 861 (2019) Sector	EIA 861 (2019) MPSC (2021, growth rate) by sector	DTE 8760s	Used same Res and Com LF as DTE 8760s	June - September	October - May	Same as above	Same as above

Source: Guidehouse analysis

Customer Counts

The number of electric customers for each segment and utility was developed using utility-specific data, and was supplemented with FERC Form 1 and EIA 861 data when necessary (primarily for C&I segmentation). Similar to the EWR study, residential segmentation used the previously described splits from statewide census data.

The number of gas customers for each utility and sector was sourced from EIA Form 176 data for 2019. Disaggregation to the residential segment level used the same methodology as the electric counts (statewide census data). Disaggregation to the C&I segment level utilized DTE data on the number of customers receiving service under the DTE GS-1 and GS-2 gas rate schedules. This is a similar methodology as was used to segment the C&I gas sales forecast.

The “CusCount” tab in the accompanying “MI_2021_DR Global Data Summary” excel file shows the disaggregate data by fuel type (electric or gas) and by region, utility, sector, and customer class. The “PivotCharts” tab summarizes the data at the different levels.

Electric Baseline Peak Demand Projections (kW/year)

The steps listed below were followed to develop the baseline peak demand projections. Guidehouse developed this by utility for the DR analysis to accommodate differences in data availability and the peak definition for each utility.

Define Peak Periods

- The peaks for summer and winter were defined as the average system-wide peak demand during the top 40 hours in each season. Seasonal definitions were based on utility-specific DR programs with specified seasonality or on utility tariffs and are noted in Table 2. The peaks and the peak hours were identified for each utility with 8760 data.

Calculate Load Factor (LF)

- To convert annual sales forecasts to peak demand values, a load factor (ratio of peak load to average load) needs to be calculated. Where 8760 loadshapes were provided, Guidehouse normalized the loadshapes and calculated the load factors as an average over each of the seasonal peak periods. For utilities that did not provide loadshapes, the load factor from DTE or Consumers was applied.

Calculate Baseline Peak Forecast.

- The load factors were applied to segment-level sales forecasts to generate baseline peak forecasts for both summer and winter

The “PeakMW” tab in the accompanying “MI_2021_DR Global Data Summary” excel file shows the disaggregate electric peak demand data by season (summer and winter) and by region, utility, sector, and customer class. The “PivotCharts” tab summarizes the data at the different levels.

Gas Baseline Peak Demand Projections (therms/year)

The gas baseline peak forecast defines the peak as the utility peak design day. Guidehouse used this definition because no utility was able to provide hourly 8760 gas consumption data, but all were able to provide peak design day consumption forecasts. These peak design days are generally defined as occurring in January.

Guidehouse calculated load factors to link the utility-provided peak design day values with annual gas sales forecasts. These load factors were used to develop peak day forecasts at the utility system level over the forecast period.

To disaggregate to the residential and C&I sector level, Guidehouse used loadshapes from the NREL Open EI database to calculate residential peak-day gas load factors. The Detroit Metro and Sault Ste Marie loadshapes were used to represent the lower and upper peninsulas respectively. These residential load factors were then applied to residential sector gas sales forecasts to determine peak day demand for the residential sector. C&I sector peak day demand values were then obtained by subtracting the residential peak demand from the previously calculated system-level peak day forecasts.

Disaggregation to the residential segment level used the same splits derived from statewide census data that were used in the electric baseline forecast and the EWR study. Disaggregation to the commercial segment level (Small C&I and Large C&I) utilized the gas sales splits derived from DTE GS-1 and GS-2 rate code data.

The “PeakTherm” tab in the accompanying “MI_2021_DR Global Data Summary” excel file shows the disaggregate gas peak demand data by region, utility, sector, and customer class. The “PivotCharts” tab summarizes the data at the different levels.

End Use Contribution to Peak Demand

For DR options where the unit impacts are characterized as “% reduction in end use load”, the end use contribution to the peak load is required for assessing DR potential. This only applies to certain DR options for C&I customers. For residential customers, the unit impacts are either represented as “kW reduction per customer” or as “% reduction in total demand”.

In order to derive the end use shares in peak demand, Guidehouse first identified the peak period for end use loadshapes by using the top 40 hours for each season of the "Other" load shape.[3] The primary data source for the load shapes was DTE’s 2015 End Use C&I loadshapes for DSMore.

The normalized loadshapes for each end use were averaged over the peak period to obtain a "peak factor", which was then applied to annual end use consumption of the base year (2019) to obtain end-use peak in MW. The end-use peak values were then used to assess each end-use’s percentage contribution to peak demand.

The “End Use Contribution to Peak” tab in the accompanying “MI_2021_DR Global Data Summary” excel file shows the end use shares in summer and winter peak demand for C&I customers.

DR Options Characterization: Unit Impacts

The unit impacts from DR options is a key input for DR potential estimation. This specifies the amount of load reduction that could be achieved per participant in a DR program.

The accompanying “MI_2021_DR Global Data Summary” excel file shows the assumed unit impacts by DR options with a documentation of the basis for the assumed values.

[3] "Other" was used because no whole building loadshape was provided.