Public Utility Commission of Texas

Texas Technical Reference Manual

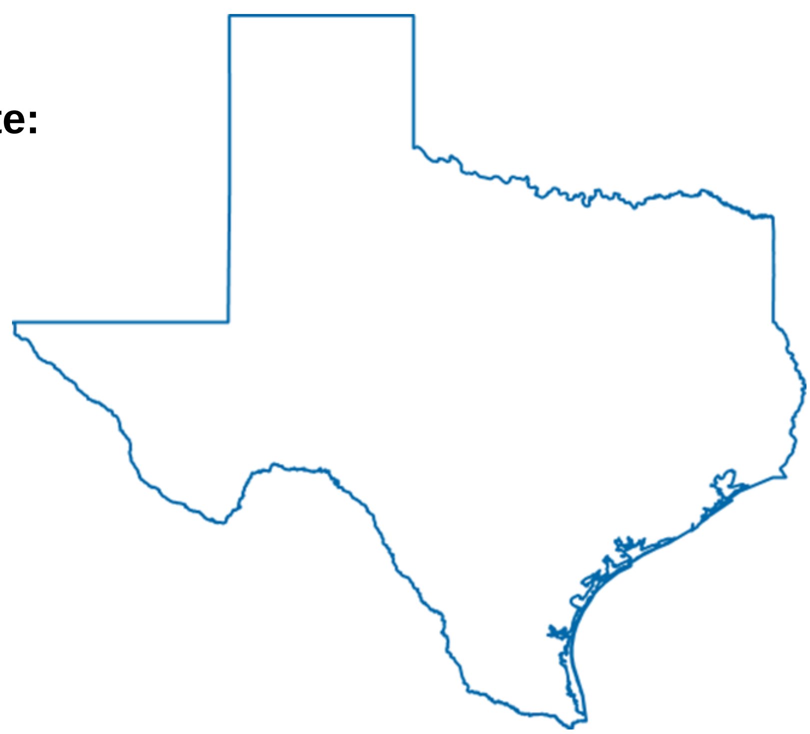
Version 6.0

Volume 1: Overview & User Guide

Program Year 2019

Last Revision Date:

October 2018



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Acknowledgements

The Technical Reference Manual is maintained by the Public Utility Commission of Texas' independent Evaluation, Monitoring and Verification (EM&V) team led by Tetra Tech. This version of the Texas Technical Reference Manual was primarily developed from program documentation and measure savings calculators used by the Texas Electric Utilities and their Energy Efficiency Services Providers (EESPs) to support their energy efficiency efforts, and original source material from petitions filed with the Public Utility Commission of Texas by the utilities, their consultants and EESPs such as Frontier Energy (TXu 1-904-705), ICF, CLEAResult and Nexant. Portions of the Technical Reference Manual are copyrighted 2001-2017 by the Electric Utility Marketing Managers of Texas (EUMMOT), while other portions are copyrighted 2001-2018 by Frontier Energy. Certain technical content and updates were added by the EM&V team to provide further explanation and direction as well as consistent structure and level of information.

TRM Technical Support

Technical support and questions can be emailed to the EM&V project manager (lark.lee@tetratech.com) and PUCT staff (therese.harris@puc.texas.gov).

1. TRM PURPOSE AND SCOPE

The purpose of the statewide Technical Reference Manual (TRM) is to provide a single common reference document for estimating energy and peak demand savings resulting from the installation of energy efficiency measures promoted by utility-administered programs in Texas. This document is a compilation of deemed savings values previously approved by the Public Utility Commission of Texas (PUCT) for use in estimating savings for energy efficiency measures. The TRM is updated annually through a collaborative process between the Electric Utilities Marketing Managers of Texas (EUMMOT) and the PUCT's third-party Evaluation, Measurement and Verification (EM&V) contractor. The data and methodologies in this document are to be used by program planners, administrators, implementers and evaluators for forecasting, reporting and evaluating energy and demand savings from energy efficiency measures installed in Texas. The scope of the TRM is measure savings; therefore, utilities' program manuals should be consulted for health and safety considerations related to implementation of measures (i.e., residential air sealing measures).

The development and maintenance of the TRM is addressed in P.U.C. SUBST. R. 25.181 (16 TAC §25.181), relating to Energy Efficiency Goal (Project No. 39674). The first two versions of the TRM were specific to measures using a deemed savings approach. Subsequent versions of the TRM also include standardized M&V protocols for determining and/or verifying energy and demand savings for specific measures or programs ((16 TAC § 25.181(q)(6)(A)).

1.1 DEEMED SAVINGS DISCUSSION

Deemed savings refers to an approach for estimating average or typical savings for efficiency measures installed in relatively homogenous markets with well-known building characteristics and usage schedules. Previous market research and building simulation tools have been used to develop estimates of "average" or deemed energy or peak savings per measure as a function of building type, capacity, weather, building schedules and other input variables. Using this approach, program savings can be estimated by multiplying the number of measures installed by the deemed or estimated savings per measure based on previous research on the average operating schedules, baseline efficiencies and thermal characteristics of buildings in a given market.

The deemed savings approach provides reasonably accurate estimates of savings in mass markets where building operating conditions, system characteristics, and baseline efficiencies are relatively well-defined. This approach is not normally used to estimate savings in less homogenous and more site-specific applications, especially in nonresidential facilities where the range of operating conditions and energy using processes is significant and can vary widely from one project to another for similar measure. Developing energy savings estimates for these more complex facilities require the use of one or more of the International Performance Measurement & Verification Protocol (IPMVP) options that require some form of on-site measurement.

By definition, deemed savings estimates require the development of engineering algorithms, tools or models to estimate average savings as a function of one or more average inputs including baseline usage patterns, equipment efficiency levels, and building thermal characteristics. This document organizes the methods and sources used to develop these average and default values by measure category and sector and lays out the resulting savings per measure estimates in the form of savings values, algorithms, and/or calculation tools for energy efficiency measures offered by utility program administrators for claiming and reporting energy savings impacts to the PUCT.

1.2 TRM SCOPE AND DEVELOPMENT CYCLE

One of the primary objectives of the TRM is the uniform application of savings methods and the assumptions behind them. This will facilitate consistency in estimating savings across programs and utility areas and in estimating program-level cost effectiveness. By establishing clear qualification criteria for the development of projected and claimed savings estimates, the TRM provides transparency of savings for all interested stakeholders.

The TRM document also provides guidance on the update frequency for key inputs and/or equations based on the vintage of the input parameters, as well as the EM&V team's assessment of the level of variability in likely savings estimates across the range of measure applications. The intent is to help participants in the energy efficiency market save money and time by providing a single source to guide savings estimates and equations.

Finally, the EM&V team will provide clear criteria for deciding whether future efficient technologies or systems are good candidates for being included in the TRM as a deemed savings measure estimate, or a deemed algorithm with stipulated or variable parameters.

The data and algorithms housed in the TRM are to be used by electric utilities who serve as program administrators for the following purposes:

1. Projecting program savings for the next year
2. Reporting program savings for the previous year.

PUCT staff has approval responsibility for the TRM (16 TAC § 25.181(q) (6) (C)). To facilitate proper vetting and collaborative input into the TRM, PUCT staff will distribute the TRM to the Energy Efficiency Implementation Project (EEIP), and will host an annual EEIP meeting to review the TRM.

1.3 TRM LAYOUT

This document is divided into separate documents for ease of use:

- **Volume 1:** TRM Overview and User Guide covers the process for TRM updates and version rollouts, weather zones, peak demand definitions, TRM structure, and the format of the TRM measure overviews.
    - **Appendix A:** Glossary of Terms
    - **Appendix B:** Peak Demand Reduction **(**Documentation of measure-level peak demand reductions[1])
- **Volume 2:** Residential Measures contains the measure descriptions and deemed savings estimates and algorithms for measures installed in residential dwellings.

[1] The measure-level peak demand reduction documentation, Appendix B, is a separate Excel spreadsheet.

- **Volume 3:** Nonresidential Measures contains the measure descriptions and deemed savings estimates and algorithms for measures installed in nonresidential businesses. Volume 3 also includes two appendices, below.
    - **Appendix C:** Nonresidential Lighting Factors Comparison Tables provides a comparison of key lighting stipulated parameters from utility lighting calculators and program manuals
    - **Appendix D:** Measure Life Calculations for Early Retirement Programs describes the method of calculating savings for early retirement programs
- **Volume 4:** M&V Protocols contains protocols to estimate claimed savings for measures that have been reviewed and approved by the EM&V team. Volume 4 also contains two appendices, below.
    - **Appendix E**: AC-Tune Up Metering Schedule
    - **Appendix F:** Counties by Weather Zone Assignment
- **Volume 5:** Implementation Guidance contains EM&V team recommendations regarding program implementation that may affect claimed savings.

2. TRM UPDATE PROCESS AND VERSION ROLLOUT

The TRM was developed in stages to ensure a smooth transition from the historic situation where a variety of different energy savings calculators and tools were used to estimate savings to a preferable situation where a common set of deemed savings methods and consistent calculators are used by all electric utilities and EESPs in Texas.

2.1 TRM VERSIONS

This fifth version of the TRM, Version 5.0, is to be used for Program Year (PY) 2018.

- **TRM 1.0** organized the deemed savings tables, algorithms and calculators that were used in 2013 to estimate deemed savings into a consistent framework with common sector, end use, and measure naming conventions across all utilities. TRM Version 1.0 also consolidated and organized the savings tools and calculators used to deem savings per measure in one place to allow for comparison of savings methods and approaches used in different utility service areas.
- **TRM 2.0,** the second version of the TRM, was finalized in April 2014 for utilities to use in planning for PY2015 projected and claimed savings. It contains prioritized changes to selected deemed savings estimates and/or calculators based on the EM&V contractor's initial reviews of deemed savings tables and calculators. It also includes documentation of currently approved peak demand reductions. An updated version, TRM 2.1, was filed in the beginning of PY2015 to provide additional clarifications as well as to include ENERGY STAR® updates and two new measures for which deemed savings were approved by the Commission since TRM 2.0 was filed.
- **TRM 3.0** was finalized in April 2015 for utilities to use in planning for PY2016 projected and claimed savings. TRM 3.0 includes additional prioritized updates informed by EUMMOT and EM&V primary research with Texas customers across all utility territories. It includes revisions and standardization to some input values and/or calculators, including consolidation of existing savings tables, and recommended seasonal time demand patterns for measures where annual hours of use are not estimated by existing tools or calculators. In addition, Version 3.0 includes standardized approaches to calculate summer and winter peak savings at the measure level and is the first TRM to include standardized EM&V protocols. This updated version, TRM 3.1, includes identified updates and reviewed M&V protocols since TRM 3.0 was filed. A redlined version of TRM 3.1 was distributed in March 2016, which added additional examples of peak demand for M&V projects, corrected errors found in the new peak demand calculations and added language regarding mechanical ventilation for new homes.
- **TRM 4.0** represented an agreed upon shift in the TRM schedule to one TRM a year for both planning and implementation to be distributed by the end of August and finalized by the end of September for use in the next program year. TRM 4.0 includes major updates for solar PV, residential envelope measures, commercial HVAC and roof measures as well as several other updates as described in the summary tables at the beginning of each volume.
- **TRM 5.0** includes baseline updates in response to the statewide adoption of IECC and IRC 2015 codes in 2016. It also includes several new deemed measures: nonresidential evaporative pre-cooling, residential showerhead thermostatic restrictor valve, residential tub spout and showerhead thermostatic restrictor valve and residential and

nonresidential pool pump. New M&V protocols were developed for Compressed Air and Variable Refrigerant Flow (VRF) projects as well as several other updates as described in the summary tables at the beginning of each volume.

2.2 TRM UPDATE PROCESS

Deemed savings input parameters in the TRM will be reviewed at least annually by the PUCT's EM&V contractor (16 TAC § 25.181(q) (6) (B)). An annual review identifies needed updates and revisions as new technologies mature and building operating environments change. The EM&V team will assess the need for changes or updates to future TRM's deemed savings based primarily on (a) feedback from the organizations that use the TRM values and equations for planning or reporting purposes, (b) EUMMOT's or the EM&V team's assessment of changes in measure technology and measure baselines due to changes in common practices, codes and/or performance standards, and (c) EM&V results that indicate reasonable updates could improve the accuracy of savings estimates. The EM&V team will make recommendations about the scope and detail needed for future updates to savings algorithms and values based on input gathered from EUMMOT, EESPs, the PUCT and other stakeholders, EM&V research and consideration of the uncertainties and the potential for bias in current TRM estimates.

The need for TRM deemed savings updates are based on the following factors: (1) the number and complexity of new measures proposed annually by utilities and EESPs; (2) the degree of uncertainty of savings estimates determined in the review process; (3) changes in baselines; (4) new data made available from site-based M&V activities; and (5) the cost of updating the TRM annually.

The petition process for establishing Commission-approved deemed values for **new** measures will continue to be the mechanism for introduction of deemed values for new measures. (16 TAC § 25.181(p) (2)). Any deemed values adopted by the PUCT through the established petition process at least two weeks prior to the submission of the draft TRM will be incorporated into the draft TRM. Any deemed values adopted by the Commission at least two weeks prior to the date of the final version of the TRM will be incorporated into the final version of the TRM. Regardless if new measures are in the TRM or not, Commission-approved measures may be included in programs 60 days after the petition is filed with the Commission.

2.3 TRM SCHEDULE

The EM&V team maintains a detailed schedule on the PUCT EM&V SharePoint site for the TRM that includes draft submission dates, comment due dates, EEIP meeting, and the date for filing the final versions. Final versions are then made available, on the PUCT website and Texasefficiency.com as well as the EM&V SharePoint site. The publication dates for each version of the TRM indicate the date that the TRM is expected to be approved by Commission staff. The TRM will be submitted to EUMMOT for review at least one month prior to the publication date. An EEIP meeting will be held annually for presentation of key changes, providing a forum for questions and comments. The application of the TRM version for program year planning and evaluation is indicated below.

Table 2-1: TRM Rollout and Applicability to Utility Plans & Program Evaluation

TRM Version and Filing Date	Program Year for Which TRM is Used	Program Year Plan Filing Date	Program Year Evaluation Report Date	Notes/Comments
TRM v1.0 Dec 2013	PY2014	April 2013	June 2015	Inventory/summary of current deemed savings approaches and differences; Foreshadowing of any anticipated changes for TRM 2.0 and 3.0
TRM v2.0 April 2014	PY2015 planning	April 2014	n/a	First version with EM&V team recommended changes, intermediate/interim/accelerated version
TRM v2.1 January 2015	PY2015 implementation	April 2014	June 2016	Revised version of TRM v2.0 with clarifications and new measures approved by the Commission
TRM v3.0 April 2015	PY2016 planning	April 2015	n/a	Includes savings updates and EM&V protocols
TRM v3.1 November 2015	PY2016 implementation	April 2015	June 2017	Updates for PY2016 implementation identified after v3.0 filing
TRM v4.0 October 2016	PY2017 implementation	April 2016	June 2018	Addressed additional updates identified as part of the annual TRM prioritization process and PY2015 EM&V
TRM v5.0 October 2017	PY2018 implementation	April 2017	June 2019	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2016 EM&V
TRM 6.0 October 2018	PY2019 implementation	April 2018	June 2020	Integrated new measures filed with the PUCT and addressed additional updates identified as part of the annual TRM prioritization process and PY2017 EM&V

3. WEATHER DATA FOR WEATHER-SENSITIVE MEASURES

For this TRM, the normalized deemed savings estimates for many weather-sensitive energy efficiency measures have been developed with simulation models that use Typical Meteorological Year (TMY) data. Both TMY2 and TMY3[2] weather data are used in the current savings estimates. To create TMY data, a single, typical meteorological year is selected and assembled from 15 to 30 years of historical data. That is, whole months of actual year weather data that represent average weather for that month over the historical period are selected from the entire range and merged together to create the TMY weather file. As such, the TMY data set represents typical rather than extreme conditions, and it is intended to represent the range of weather phenomena specific to that location with annual averages that are consistent with the location's long-term weather conditions. The TMY data sets were produced by the National Renewables Energy Laboratory's (NREL) Electric Systems Center under the Solar Resource Characterization Project, which is funded and monitored by the U.S. Department of Energy's Energy Efficiency and Renewable Energy Office. This data represents typical rather than extreme conditions. The TMY3 data sets are the third generation of TMY files. They are based on more recent and accurate data and use a different format than previous versions. They are derived primarily from the 1991 to 2005 National Solar Radiation Data Base (NSRDB) archives. Going forward, only TMY3 data sets will be used.

The TMY3 data sets include the following hourly values of solar radiation and meteorological elements:

- Dry bulb and wet bulb temperature
- Relative humidity
- Wind speed and direction
- Cloud cover
- Multiple solar radiation values

Energy and demand savings for weather-sensitive measures are typically estimated using building simulation modeling as it can produce hourly energy consumption estimates by applying location-specific historical weather information contained in the TMY files.

3.1 TRM CLIMATE ZONES/REGIONS

For the simulation of savings estimates for weather-sensitive energy residential efficiency measures, there are currently five TMY3 files (weather stations) that are used to represent the areas served by the Texas electric utilities.[3] The nonresidential savings estimates are derived from five separate weather stations using TMY3 weather. The five TRM climate zone/regions and their representative weather station city locations are shown in Table 3-1. For application of the energy and demand savings developed on this basis, the TRM climate zones/regions are

[2] The TMY3 data sets are publicly available at: http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/ and as supporting documentation to the TRM Version 2.0.

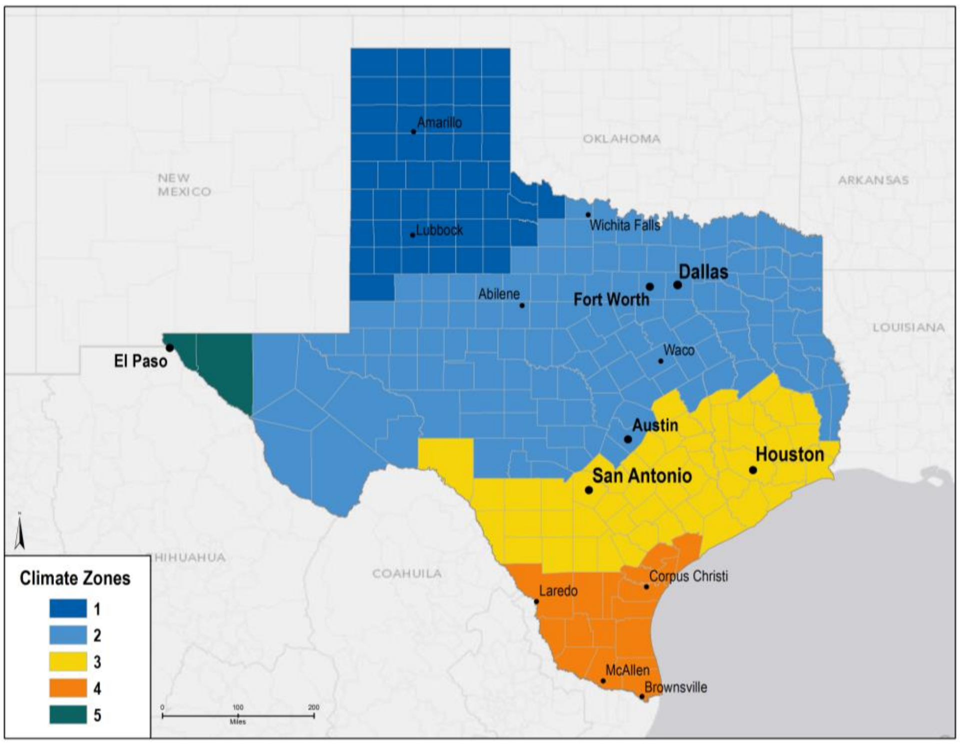
[3] The TRM climate zone/regions and county-level assignments were created and are currently maintained by Frontier for the Electric Utilities Marketing Managers of Texas (EUMMOT).

mapped to Texas counties. This mapping is represented visually in Figure 3-1, and available in table format.

Table 3-1: Texas TRM Climate Zones

Representative City	TRM Climate Zone	TRM Region Name	Representative Weather Station
Amarillo, TX	1	Panhandle	Amarillo International Airport [Canyon - UT]
Dallas, TX	2	North	Dallas/Fort Worth International Airport
Houston, TX	3	South	George Bush Intercontinental Airport
Corpus Christi, TX	4	Valley	Corpus Christi International Airport [UT]
El Paso, TX	5	West	El Paso International Airport [UT]

Figure 3-1: TRM Climate Zone Assignments by County



3.2 HISTORY AND STATUS OF WEATHER STATION APPLICATIONS

For residential measures, Frontier initially used four climate zones for deemed savings development in Texas. They were Houston, Dallas/Fort Worth (DFW), Amarillo, and South Texas, loosely aligning with the contours of reasonable Texas climate zones and population centers of the largest IOUs (CenterPoint, Oncor, Xcel/SPS, and AEP-TCC, respectively). AEP-SWEPCO (NE Texas) and AEP-TNC (Abilene) used the deemed savings developed from the Dallas-Fort Worth (DFW) weather data. Entergy used Houston deemed savings, and TNMP used either the DFW or Houston deemed savings, depending on the relevant service territory. When El Paso Electric (EPE) was added to the Energy Efficiency Rule, EPE initially used the deemed savings that had been developed for the DFW region. That is, deemed savings for El

Paso weather data were not regenerated for older measures, those measures continued to use the Dallas/Fort Worth values for the EPE service area. However, when deemed savings for newer measures were developed, the El Paso climate zone was added.

In addition, weather stations, other than the five weather stations currently used for residential measures, have sometimes been used for nonresidential measures, especially for savings estimates not developed by Frontier. The result is that there are currently *nine* different weather stations used by the TRM residential and nonresidential measures, as summarized in Table 3-2 and Table 3-3. Furthermore, some of the deemed savings estimates use TMY2 weather data, rather than the latest TMY3 data.

These were defined and should be used for all weather-sensitive measures going forward.[4]

Table 3-2: Weather Station Codes

Weather Station Code	Weather Station City Location
AMA	Amarillo
DFW	Dallas/Fort Worth
AUS	Austin
HOU	Houston
SAT	San Antonio
CRP	Corpus Christi
BRO	Brownsville
MCA	McAllen
ELP	El Paso

[4] There may always be exceptions for calculators and modeling tools that serve the national market, such as ENERGY STAR® calculators, which typically have a more limited selection of weather stations available.

Table 3-3: Summary of Weather Files Used for Energy Efficiency Measures

Sector	Measure ID	Weather Station Code (Region)								
		AMA (1)	DFW (2)	AUS (2)	HOU (3)	SAT (3)	CRP (4)	BRO (4)	MCA (4)	ELP (5)
Residential	All Measures[5]	1	1	--	1	--	1	--	--	1 & 0
Non-Res	All HVAC	1	1	--	1	--	--	1	--	1
Non-Res	VFD on AHU	1	1	--	1	1	--	--	--	1
Non-Res	ENERGY STAR® Roofs	1	1	1	1	--	--	1	--	--
Non-Res	Door Heater Controls	1	1	--	1	--	--	--	1	1
Non-Res	ECM Evap Fan Motors	1	1	--	1	--	--	--	1	1
Non-Res	Electronic Defrost Controls	1	1	--	1	--	--	--	1	1
Non-Res	Night Covers for Open Refrigerated Cases	1	1	--	1	--	--	--	1	1
Non-Res	Lodging Guest Room Occupancy Sensor Controls	1	1	--	1	--	--	--	1	1

[5] As explained in this section, some older residential measures do not include deemed savings for the El Paso weather zone/region, hence the “1 & 0” for the El Paso weather station.

4. PEAK DEMAND DEFINITIONS

P.U.C. SUBST. R. 25.181 defines peak demand, peak demand reduction and the peak period for the Texas energy efficiency programs (16 TAC § 25.181 (c) (44) (45) (46)). This section summarizes the Electric Utilities Marketing Managers of Texas' (EUMMOT) and EM&V team's agreed upon approach to calculating peak demand savings across measures using methodologies guided by these definitions. This approach will be used going forward as measures are prioritized for TRM updates or as new measures are added.

4.1 OVERVIEW

The definition of *peak demand reduction* in the EE Rule of the PUCT has evolved since 1999, when the present framework for utility programs was established. Deemed savings values and algorithms for peak demand reduction and coincidence factors (CF) reflect the definitions and requirements within the EE Rule that were in place at the time the PUCT approved the values. Depending upon when the peak demand reduction and CFs were developed, these values may reflect:

1. The effect of the measure at the time of the utility's expected system peak;
2. The *average* demand reduction of a measure across a subset of the full peak demand period specified in the rule; or
3. The *maximum* hourly impact of a measure within the peak hours specified in the rule, regardless of whether the time of the maximum impact coincided with the utility's peak demand.[6]

Changes in the definitions within and interpretations of the EE Rule have resulted in some inconsistencies in how peak demand reduction has been estimated in the existing deemed savings in the TRM.

The objectives of this section of the TRM are to: 1) present an overview of the approach developed by Frontier Associates to establish the summer peak hours/window and winter peak hours/window to be used for calculating the peak demand reduction or CF for measures, and 2) provide clear guidance on calculating peak demand reduction and CFs based on these established winter and summer peak hours/windows.

The end objective is to improve the consistency of approach to estimating peak demand reductions across measures. Recognizing that it is not practical to update the peak demand reduction estimates in the TRM all at once, peak demand estimates will be updated to reflect this approach in accordance with the process for identifying updates for the TRM as specified in TRM 3.0 Volume 1, Section 2. Any updates will also be noted in the TRM Appendix B, Peak Demand Reduction Documentation spreadsheet. Additionally, demand reduction estimates for measures submitted through the petition process will also be reviewed for consistency with the approach.

[6] This appendix does not apply to the calculation of peak demand reduction from load management programs, which is addressed through a separate process.

4.2 APPROACH TO IDENTIFYING PEAK HOURS

This section describes the probability-based method developed to identify when utility system peaks (referred to as system peak coincident demand) occur in each of the TRM climate zones, for use in estimating summer and winter peak demand reduction attributable to implementation of energy efficiency measures. This approach is summarized in two steps:

1) Identify how individual utility territories map to the TRM climate zones for which savings are presented[7]
2) Establish the predicted peak hours in each season for each utility (i.e., summer and winter), using a regression model and historical utility and ERCOT load data to estimate a relationship between hourly energy use in TRM climate zone-specific peak hours and a set of explanatory variables (e.g., temperature, time of day)

Additional details regarding this approach are provided in a white paper, *Approach to the Estimation of Peak Demand Reduction*, including the process of mapping utilities to climate zones, and estimation of timing seasonal peak demands within TRM Climate Zones.[8]

4.2.1 Mapping Weather Zones to Utility Service Areas

Historical utility system load data are required for estimating peak hours. To identify the utility-specific peak hours, these load data need to align with weather zones that correspond to specific utility service areas. Several issues complicate this process:

- The TRM delineates the weather stations used to represent a TRM Climate Zone.
- Utility system load data to be mapped to TRM Climate Zones are available from several sources:
  - ERCOT—publicly available through ERCOT, these data are specific to ERCOT Weather Zones, which then need to be aligned with TRM Climate Zones and utility service areas
  - Utility-Specific—in several cases, load data have been provided by specific utilities (i.e., Climate Zone 1 and 5 data were provided by Xcel and El Paso, respectively)
- Some climate zones match well with a specific utility territory, while other climate zones encompass numerous utilities (some of which are outside the ERCOT market). Another way to put this is that many utilities do not lie within a single TRM Climate Zone, which adds complexity to the alignment effort.
- Not all utility systems within a given climate zone may reach their respective peak loads at the same interval and hour due to the composition of their customer base. Since the EE Rule and definition of peak demand reduction adopted here require consideration of

[7] See TRM Vol.1 Section 3 for more detail on TRM Climate Zones definitions and how they map to city/weather zone/region.

[8] *Approach to the Estimation of Peak Demand Reduction*. Frontier Associates, 2014. Available at: http://www.texasefficiency.com.

utility-specific peak demand, this introduces another challenge to determining the appropriate peak period.

To determine the most appropriate mapping between available electric system load data and weather zone, Frontier performed a correlation and ranking analysis. First, the analysis considered how well ERCOT-wide load peaks in demand (using top 20 hours per season) correlated with load across the different weather zones within ERCOT territories.[9] Second, the analysis assessed the ERCOT-specific peaks and how well those correlated with utility-specific service territories. For ERCOT utilities, service areas more closely corresponded to specific ERCOT Weather Zones geographically (e.g., Oncor to the Central zone, CenterPoint to the Coastal zone).[10] For several non-ERCOT utilities (i.e., Entergy, SWEPCO), Frontier conducted a similar analysis using utility-specific system load data to determine whether their system peaks coincided with those of neighboring ERCOT Weather Zones.

Based on this analysis, the identification of peak demand hours using ERCOT weather zone load data provides a reasonable approximation to the peak demand hours for the utility systems within those zones.[11] Among non-ERCOT utilities, utility load data were provided for Xcel/SPS and El Paso Electric, which most appropriately mapped to TRM Climate Zones 1 and 5, respectively. For SWEPCO and Entergy, high correlation with neighboring ERCOT zones obviated the need to establish separate TRM Climate Zones for these utility systems and supported application of ERCOT Weather Zones as a proxy.

Table 4-1 provides a summary of this mapping effort, with additional details available in the *Approach to the Estimation of Peak Demand Reduction*.[12]

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[9] Participating ERCOT utilities include AEP TCC, AEP TNC, CenterPoint, Oncor, Sharyland, and TNMP.

[10] ERCOT's weather zones are designed to represent geographical regions where climate and residential load patterns tend to be similar. Utility service area boundaries are also taken into account in their construction. See *ERCOT Load Profiling Guide*, Section 13: Changes to Weather Zone Definitions, October 1, 2010, at http://www.ercot.com/mktrules/guides/loadprofiling/current.

[11] Each of the correlation relationships examined through this study found to be stronger in the summer than in the winter months.

[12] Available at: http://www.texasefficiency.com/index.php/regulatory-filings/deemed-savings.

Table 4-1: TRM Climate Zone Mapping to Utility Service Area

TRM Climate Zone	TRM Region Name	Representative City	Utilities Serving Within Each Zone	Mapping to Electric System Load Data
1	Panhandle	Amarillo	AEP TNC, Xcel/SPS, SWEPCO	Outside ERCOT (using system load data from Xcel/SPS)
2	North	Dallas	AEP TNC, Entergy, Oncor, Sharyland, TNMP, SWEPCO	Sum of load data from five ERCOT zones: Far West, West, North, North Central, East
3	South	Houston	AEP TCC, CenterPoint, Entergy, TNMP	ERCOT's Coast Weather Zone
4	Valley	Corpus Christi	AEP TCC, Sharyland	ERCOT's Southern Weather Zone
5	West	El Paso	El Paso Electric	Outside ERCOT (using system load data from El Paso)

4.2.2 Identifying the Most Probable Hours for System Peaks

This estimation approach involves identifying a set of hours within the PUC EE rule-defined summer and winter peak demand periods during which utilities' system peaks are likely to occur. Given variability in when peaks occur, identifying several potential peak hours provides a better chance of estimating the actual peak than an approach that relies on a single hour. Frontier determined that using the 20 most probable hours for this estimate (based on a regression of historical load data) provides a sufficient range of hours to assign the highest probability of being within the set of actual peak hours.

To estimate the top 20 hours most likely to be summer and winter peak hours, a logistic regression (referred to here as *peak probability analysis* [PPA]) was performed using weather data and the historical load data previously discussed. To estimate summer and winter peak probabilities for the five different TRM Climate Zones, typical meteorological year (TMY) weather data were used from five Texas weather station locations, noted above in Table 3-1.[13] Parameter estimates from the logistic regression were applied to the TMY data for each location to estimate each hour's probability of being a peak demand hour, and identify the 50 hours for each peak demand season (summer and winter) in the TMY3 datasets with the highest probability of being a peak hour.

While the objective of this approach is to develop a set of the top 20 hours, models need to produce probabilities for more than 20 hours to ensure some of these hours do not effectively occur over non-weekdays when TMY data are used in evaluating load patterns that have calendar-dependent components (differences in usage on weekdays vs. holidays and

[13] This analysis uses TMY3 weather data, representing average weather data from 1991 to 2005. Older versions of TMY data sets represent average weather from earlier periods (e.g., TMY2 uses 1961 to 1990). More information regarding TMY data sets are available through NREL: http://www.nrel.gov/docs/fy08osti/43156.pdf.

weekends). In the summer, utility system peaks typically occur on weekdays; moreover, the PUC rule excludes holidays and weekends from the peak period. TMY data are time series of observed climate data, which are entirely independent of the day of the week on which a given observation was made. However, when the TMY data are used in practical applications (e.g., building simulation modeling), occupancy and operation patterns that reflect actual differences in weekday and weekend energy use are super-imposed on the climate data, with a specific calendar year. The calendar year selected determines the weekday/weekend/holiday framework for the weather data. To ensure a minimum of 20 probable peak hours could be identified for any given model year (January 1 start date) after removing hours that fall on weekends, Frontier determined that sets of 50 hours were required.

The logistic regression model uses hourly load datasets for several historical years (the models in this analysis used system load data from 2007 through 2014) to estimate the relationship between setting a peak in a given hour and a set of explanatory variables, including temperature variables and dummy variables representing time-of-day and month-of-year. The hourly load data reflect the geographical areas depicted in Table 3-2, while the weather data correspond to the representative weather stations of those TRM Climate Zones.

The regression assigns marginal probabilities to changes in the explanatory variables. Given the estimated relationship between each peak hour and the explanatory variables, a probability is calculated for setting a peak in a given hour based on the temperature in that hour from the TMY weather data and the month in which it occurs, and which hour of the day it is.

Within section 4.6, Table 4-5 through Table 4-14 summarize the 50 highest probability summer and winter peak hours for TRM Climate Zones 1 through 5 in the TMY3 datasets for the weather stations specified in Table 3-1.

4.3 ESTIMATING PEAK COINCIDENT DEMAND REDUCTIONS

The approach to identifying system peak hours described in section 4.2 provides a basis for estimating peak coincident demand reductions attributable to the implementation of energy efficiency measures in Texas. This is based on measure-specific load during the identified peak hours according to section 4.2.2 and presented in Table 4-5 through Table 4-14.

This section explains how the probable peak hours are used to estimate deemed peak coincident demand savings for three kinds of measure load conditions: (1) those developed using hourly building simulation models, (2) those for which annual energy savings can be estimated and for which normalized load shapes are available, and (3) lastly, for those based on field data from M&V monitoring of equipment energy use. Several approaches may be used to determine measure load and the following three examples are meant to demonstrate how those measured load results can be applied to derive reportable electricity demand reductions in Texas.

Using Building Simulation Models (for Weather-Sensitive Measure Impacts)

In some cases, deemed savings are estimated using building simulation models, which estimate the hourly impacts of implementing energy-efficiency measures (i.e., modeling the difference between base and change case). When simulation models are run using the TMY3 datasets from the weather stations specified in Table 3-1, peak demand reductions can be estimated by determining the appropriate top 20 of 50 hours available for the climate zone in question (from one of Table 4-5 through Table 4-14). The 20 hours to be used are selected from the appropriate set of 50 hours according to a two-step process:

1. Assign a day of the week to each of the 50 hours according to the day it would have fallen on in the simulation model and screen out all hour intervals falling on weekends.
2. Sort the remaining weekday intervals in descending order by probability and select the top 20.

Once the appropriate set of 20 probable peak hours has been identified, the unadjusted hourly kW savings from the simulation models in each of those intervals are paired with that hour's peak demand probability factor. The final attributed demand savings should be estimated as the probability-weighted average of the hourly demand reductions estimated in each of those 20 hours.

Example 1: Measures Using Building Simulation Models

Analysis Scenario: High efficiency commercial air conditioning unit installed in TRM Climate Zone 4.

Step 1: Run the base and change case simulation models to generate 8,760 hourly simulation results

a) Use TMY3 data corresponding to the Corpus Christi International Airport weather station (as shown in Table 3-1) from the National Renewable Energy Laboratory (NREL) website: http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/[14]
b) Run the building simulation model with the selected TMY3 weather data and assign a *calendar year*

Step 2: Calculate the ***summer peak demand savings***.

a) Use the PPA in Table 4-8 to identify the top 20 weekday hours and associated peak demand probability factors from the 8760 hourly simulation model output as follows.
    i. Based on the Calendar Year used, for every value in the table, assign each record a weekday or weekend/holiday flag based on the day in the month/day/hour value.
    ii. Select the top 20 *weekday* records. Separate weekdays from weekends and select the top 20 weekday hours by ranking the weekdays according to the *peak demand probability factor* in the last column of the PPA table (highest to lowest). The month/day/hour combinations provide the specific intervals for which hourly demand reductions should be extracted from the 8760 building simulation output and used to calculate the *summer peak demand* values.

b) Calculate the claimed coincident *summer peak demand reduction by taking the probability-weighted average of the hourly demand reduction estimates from the models* as shown in the following equation:

[14] See User's Manual for TMY3 Data Sets for more information: http://www.nrel.gov/docs/fy08osti/43156.pdf.

$$Peak\ Demand\ Savings\ (kW) = \frac{\sum_{hr=1}^{20} PDPF * Unadjusted\ Peak\ Demand\ Reduction}{\sum PDPF}$$

Equation 1

Table 4-2 provides an example calculation for a simulation model run for TRM Climate Zone 4, in which the simulation was run for calendar year 2006 (January 1 = Sunday).

Table 4-2: Example of Probability-Adjusted Summer Coincident Peak Demand Calculation Using Hourly kW from Simulation Model Results

Month	Day	Hour Ending	Relative Probability PDPF	Unadjusted Peak Demand Reduction (kW)	PDPF*Peak Demand Reduction
8	18	16	0.380	4.31	1.64
8	9	17	0.305	4.35	1.33
8	9	16	0.302	2.95	0.89
8	7	17	0.247	4.11	1.02
8	15	17	0.247	3.33	0.82
8	16	17	0.247	4.02	0.99
8	10	17	0.247	3.18	0.79
8	7	16	0.234	4.00	0.94
8	15	16	0.234	3.05	0.71
8	16	16	0.234	4.41	1.03
8	10	16	0.234	3.22	0.75
8	17	16	0.234	3.75	0.88
6	7	17	0.232	4.23	0.98
8	9	15	0.201	3.73	0.75
8	8	17	0.188	3.70	0.70
8	17	17	0.188	3.97	0.75
8	4	17	0.188	4.13	0.78
8	11	17	0.188	4.20	0.79
8	18	17	0.188	4.37	0.82
8	4	16	0.186	3.01	0.56
			4.71	**Totals**	**17.91**
Probability-Weighted Peak Coincident Demand Reduction (kW)					**3.81**

Step 3: Calculate the ***winter peak demand*** savings using the values in Table 4-13. Use the same approach described above for calculating summer peak demand savings.

Step 4: Report the ***claimed peak demand*** value. Depending on the measure, either a summer peak or a winter peak demand (usually the highest of the two) would be reported as the c*laimed peak demand* value. The basis for the value reported (summer or winter hours) also needs to be reported (identified).

For this approach to be valid, the simulation models must use the same TMY3 datasets for which the peak hours were identified by applying the relationships developed with the logistic regressions as specified in Table 3-1.

Using Normalized Load Shapes (for Non-Weather-Sensitive Measure Impacts)

Many deemed savings are estimated without using TMY3 data. For certain measures (particularly measures that are not weather-sensitive, such as residential lighting or appliance measures), peak demand reductions have typically been estimated as a function of annual energy savings estimates using a coincidence factor (i.e., ratio demonstrating the measure-specific load at the time of a utilty system peak). For these measures, a method is presented to maximize use of the available information and what is known about the probability of peaks occuring in given hours of the summer and winter peak demand periods.

The peak demand probability factors (PDPF) estimated for specific intervals (month-day-hour combinations) are driven by the temperatures associated with those intervals in the TMY3 data. The PDPFs developed for intervals in the TMY3 data provide a reasonable guide to the likelihood of a system peak demand in a given hour or month-hour combination within the summer or winter peak demand periods, which can be applied for estimating coincident peak demand savings for other (non-TMY3 based) measures. The PDPFs can be aggregated for each hour—or month-hour combination—from the PPA Table 4-5 through Table 4-14.

for the appropriate TRM Climate Zone according to the number of times that hour (or month-hour combination) is repeated in the 20 most probable peak hours.[15] The result of aggregating relative probabilities in this fashion according to hours or hour-month combinations from the top 20 values in the PDPF tables are presented in Table 4-15 through Table 4-24 and Table 4-25 through Table 4-34, respectively.

Typically, load shapes for these kinds of loads will reflect hourly fluctuations in usage patterns: in some cases, load shapes are modified by monthly factors reflecting monthly variations in usage (as in the load shapes included in the Building America Analysis spreadsheets used as inputs for residential lighting and appliance measures).[16] Because the regression analysis provides information about the influence of both the hour of the day and the calendar month in which a given hour falls, both pieces of information should be used in estimating peak demand reductions when the data are available: the PDPF of each month-hour combination in which a top 20 peak hour occurs for each zone are provided in Table 4-25 through Table 4-34. If all that is available is an hourly load shape, then peak demand impacts can be estimated using the

[15] Note that in working with load shapes we revert to not having information about whether a given peak interval would be on a weekend. As such, for this analysis the top 20 hours are simply the 20 hours of highest probability selected from the 50 hours identified in the PPA tables.

[16] Hourly and monthly residential load shapes are available from the National Renewable Energy Laboratory's 2014 Building America House Simulation Protocols and associated analysis spreadsheets. See NREL website for more information: http://energy.gov/eere/buildings/house-simulation-protocols-report.

relative probability of a summer or winter peak occurring in a given hour of the day, and these PDPFs are provided in Table 4-15 through Table 4-24. Load shapes can then be used in conjunction with the PPA tables to establish a measure's peak demand reduction.

Example 2: Measures Using Normalized Load Shapes

Analysis Scenario: Residential efficient lighting measures in TRM Climate Zone 2, corresponding to TMY3 weather data for Dallas (as shown in Table 3-1).

Step 1: Identify the appropriate lighting end use load shape for this analysis

a) Setting aside the possibility of generating an 8760 hourly end use load shape through simulation modeling, for this example we draw from the NREL 2014 Building America House Simulation Protocols and associated spreadsheets.[17]

Step 2: Calculate the ***summer peak demand***.

a) Identify the peak hours or month-hour combinations from the appropriate table and associated PDPFs.
    i. The load shape for residential lighting in the Building America analysis spreadsheet has both hourly and monthly components, so the appropriate reference table for determining the summer peak demand reduction for TRM climate zone 2 for this example is Table 4-26.
    ii. When the best available data are hourly load shapes that do not vary across the year (e.g., by month), then select the appropriate tables for summer and winter peaks for the TRM Climate Zone in question from among Table 4-15 through Table 4-24 and apply the below-described methodology (absent the monthly modifications).

b) For each month and hour ending identified in the PDPF tables (in this case, Table 4-26), obtain the hourly PDPF values for the peak hours, and from the source load shape (in this case, the Building America analysis spreadsheet) select the monthly shares of annual load for the peak months.
    i. When working with monthly shares of annual load—as in this example, the daily share of monthly load must also be calculated (as simply the reciprocal of the number of days in the month)

c) Estimate the Hourly Share of Annual Load (values in rows 1-7 of column H in Table 4-3) for each of the month-hour ending combinations by multiplying the three values identified in the previous step
    i. Multiply the hourly share of daily load (in column E) by the monthly share of annual load (column F) and the daily share of monthly load (column G). ((cell H1 in Table 4-3 below is calculated by multiplying cells E1 x F1 x G1 or $0.015*0.058*0.032 = 2.82 \times 10^{-5}$).

d) Calculate the *Probability Weighted Peak-Coincident Load Share* (column H row 8 of Table 4-3) by taking the product of each hour's *relative probability* (column D) and the

[17] The BA Analysis Spreadsheets can be downloaded at this address: http://energy.gov/eere/buildings/building-america-analysis-spreadsheets.

Hourly Share of Annual Load (in column H) and then taking the sum of each of these products.

e) Calculate the *summer peak demand savings* (in cell H10) by multiplying the estimated *annual energy savings* (value in cell H9, Table 4-3) by the *probability weighted peak-coincident load share* (value in cell H8).

Table 4-3: Example of Probability-Adjusted Summer Peak Demand Calculation Using Load Shapes

(A) Row	(B) Month	(C) Hour Ending	(D) Relative Probabilit y PDPF	(E) Hourly Share of Daily Load	(F) Monthly Share of Annual Load	(G) Daily Share of Monthly Load	(H) Hourly Share of Annual Load
1	7	16	0.257	0.015	0.058	0.032	2.82E-05
2	7	17	0.244	0.056	0.058	0.032	1.05E-04
3	7	15	0.153	0.026	0.058	0.032	4.89E-05
4	8	15	0.131	0.026	0.065	0.032	5.49E-05
5	8	16	0.095	0.015	0.065	0.032	3.17E-05
6	8	17	0.070	0.056	0.065	0.032	1.18E-04
7	7	18	0.050	0.078	0.058	0.032	1.47E-04
8	***Probability Weighted Peak Load Share***						***6.62E-05***
9	***Annual Energy Savings (kWh)***						***800***
10	***Summer Peak Demand Savings (kW)***						***0.053***

When the best available data are hourly load shapes that do not vary across the year (e.g., by month), calculation of the hourly share of annual load (the values in column H of Table 4-3) is greatly simplified: divide the load shape values by 8760, the number of hours in a year.

Step 3: Calculate the ***winter peak demand*** by repeating the procedure outlined in Step 2 using the appropriate table of winter peak hours and relative probabilities for the climate zone in question (in this case, Climate Zone 2).

Step 4: Report the ***claimed peak demand savings*** value.

a) Depending on the measure, either the summer peak or winter peak demand reduction would be used (usually the higher of the two) as the c*laimed peak demand reduction* value. The basis for the value (summer or winter hours) would also need to be reported.

Estimating Coincident Peak Demand Impacts with Field Data from M&V Activities (for Non-Weather-Sensitive Measure Impacts)

Depending on the nature of a given project, field data collection periods for estimating annual energy savings and peak demand reductions may vary. While field data collected during the summer and winter peak months is preferable for estimating summer and winter peak demand reductions (respectively), field data are not always collected during these periods. For projects or measures affecting loads that are not weather-driven, peak demand impacts can still be estimated.

Sufficient field data should be collected to allow for the construction of an hourly load shape that characterizes the fluctuations in the energy savings being produced by the implemented measure over the appropriate time period.

Example 3: Measures Estimating Peak Demand Impact with Field Data from M&V Activities (for Non-Weather-Sensitive Measure Impacts)

<u>*Analysis Scenario*</u>: A 200 horsepower pump motor for an industrial process is retrofitted with variable speed controls. Business operates 12 hours per day, Monday through Friday, closed weekends and holidays. Pump motor field metering data below provides the following hourly kW reduced profile for a typical work week, or billing hour KW load reductions. This customer is located in TRM Climate Zone 4, corresponding to TMY3 weather data for Corpus Christi (as shown in Table 3-1) (summer peak hours are highlighted in Figure 4-1).

Figure 4-1: Example 3 Sample of Hourly kW Savings for VFD Controls Application

Demand Reduction Profile for VFD on 600 Hp Motor - Variable Operations 12 hour per day Monday - Friday																								
Day/Time	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
Sunday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Monday	0	0	0	0	0	0	0	150	550	550	550	550	550	550	550	550	400	400	400	50	0	0	0	0
Tuesday	0	0	0	0	0	0	0	90	126	126	126	126	126	126	126	126	126	0	0	0	0	0	0	0
Wednesday	0	0	0	0	0	0	0	39	63	63	63	63	63	63	63	63	63	225	225	50	0	0	0	0
Thursday	0	0	0	0	0	0	0	175	225	225	225	225	225	225	225	225	55	10	0	0	0	0	0	0
Friday	0	0	0	0	0	0	0	85	112	112	112	112	112	112	112	112	112	112	112	50	0	0	0	0
Saturday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Step 1: Estimate the ***summer peak demand reduction***. Create a *probability-adjusted peak demand load savings profile table* (i.e. analysis table) similar to Table 4-4 below using the appropriate PDPFs for the climate zone, in this case Table 4-18.

a) Populate the two left columns of the analysis table (*hour ending* and *relative probability*) with values from the appropriate PPA table (this example uses the hours and relative probabilities from Table 4-18)

b) Calculate the a*verage hourly demand reduction* for each hour in the analysis table created in Step 1 (for Climate Zone 4, hours ending 15:00, 16:00, and 17:00)
    a. Sum the observed demand savings for each hour and divide by the number of observations for that hour (i.e. observations=5)

c) Calculate each hour's *probability-weighted demand reduction* by multiplying the *relative probability* of peak in each hour by the *average hourly demand reduction* for that hour

d) Calculate the Peak Demand Reduction by summing the hourly Probability-Weighted Demand Reduction values

Table 4-4: Example 3: Probability-Adjusted Summer Peak Demand Calculation Using Load Savings Profile (from field data)

Hour Ending	Relative Probability PDPF	Average Hourly Demand Reduction (kW)	Probability-Weighted Peak Hour Demand Reduction (kW)
17	0.481	153.7	73.9
16	0.478	108.0	51.6
15	0.041	106.7	4.4
Total Probability Weighted Peak Hours Demand Savings (kW)			***129.9***
Summer Peak Demand Savings (kW)			***129.9***

Step 2: Calculate the ***winter peak demand reduction*** by repeating the procedure outlined in Step 1, but using the appropriate table of winter peak hours and relative probabilities for the climate zone in question from among Table 4-10 through Table 4-14 (in this case, Table 4-13).

Step 3: Report the ***claimed peak demand*** value. Depending on the measure, either the summer peak or winter peak demand reduction would be used (usually the higher of the two) as the c*laimed peak demand reduction* value. The basis for the value (summer or winter hours) would also need to be reported.

4.4 CONSISTENCY WITH EE RULE

Total System Peak versus Residential and Commercial Class Peaks

A literal reading of the "Goal" language in the EE Rule suggests that peak hours should be identified that coincide with the peak of residential and commercial loads, rather than total system loads. Nonetheless, total system peak data are used in these calculations, for the following reasons:

- Residential plus commercial load data cannot be obtained for the ERCOT utilities that would match the PUCT's definition. ERCOT does not track which customers served at primary or secondary voltage have Manufacturing Tax Exemption Certifications, and thus can "opt-out" from programs by declaring themselves to be industrial loads. For both ERCOT and non-ERCOT utilities, the "opt-out" industrial customers vary over time.
- ERCOT could subtract customers with a billing demand of over 700 kW in two months within a 12-month period from total system load for each ERCOT weather zone, providing an estimate of residential plus commercial load. However:
    - These would not exactly meet the requirements of the rule;
    - These data are not publicly available; and
    - ERCOT management approval would be required to obtain data prior to September 2013.

Consequently, utility system load data including all customers are used in the calculations presented here. Since industrial loads tend to be non-weather-sensitive, the use of demand data including all customers is not likely to introduce significant error into the calculation. It is assumed that residential and commercial sectors will tend to peak when the aggregate load on the utility system reaches peak.

Furthermore, estimation of total system peak is consistent with definitions of peak demand reduction used in system planning and rate design activities.

Modeling Peak Periods Using Historical Load Data

The PPA modeling used to generate the top 40 hours by season and climate zone relied primarily on load data from 2007 through early 2014. The eight years of load data obtained from ERCOT and the non-ERCOT utilities were more than sufficient to establish strong regression relationships between load levels and explanatory variables.

Climate Zone Mapping to Utility Service Areas

The EE Rule definition of peak demand is specific to demand occurring at a utility's system peak. The approach used through mapping utility territories to load data and aligning these with TRM Climate Zones sufficiently approximates utility peak demands given availability of data; however, it is worth clarifying a few points in this methodology where assumptions were required to meet these criteria.

First, this approach utilized available data to approximate peaks occurring in utility service areas. TRM climate zones/regions are the geographic convention used throughout the TRM to assign weather region and provide consistency in calculating weather-sensitive impacts for energy efficiency measures. Through the assumptions used in linking utility service areas to specific climate regions, this approach to estimating peak hours (and calculating demand impacts) provides an appropriate approximation for the peak periods of these utility-specific territories.

Second, while TRM Climate Zones 1 and 5 utilized utility-specific load data, other climate zones relied on ERCOT load data for approximating peak probabilities (each of which included several utility services areas).

Finally, utility services areas do not always align with specific TRM Climate Zones, and often these territories will span more than one climate zone. By using participant ZIP codes to map individual utility customers to the appropriate climate zone, utility-specific peak impacts will be tailored to these instances.

4.5 DOCUMENTATION AND TRACKING REQUIREMENTS

Whenever the PPA method is employed, the following information must be specified and tracked in TRM Appendix B, or documentation made available in a centralized location:

- The Calendar year used for the PPA process
- Peak demand season indicator to specify the season basis for the claimed peak demand (i.e., summer or winter)[18]

[18] While either summer or winter impacts can be used as claimed peak demand savings in relation to savings goals, there is value in having both summer ***and*** winter estimates available for planning purposes. In the process of calculating measure-specific peak demand, it is recommended that estimates of both summer and winter impacts are provided, unless cost prohibitive.

- Load shapes—all building, end use, or measure load shapes utilized for these calculations should be made available in a centralized location (e.g., EUMMOT website). Sources of these data should be specified.

4.6 PEAK PROBABILITY ANALYSIS (PPA) TABLES

The following tables are extracted from the white paper, *Approach to the Estimation of Peak Demand Reduction,* and provide the peak probability factors by season and TRM Climate Zone that map utility service areas to highest probability peak hours for summer and winter peaks.

Table 4-5: Highest Probability Summer Peak Hours Using TMY3 Data: TRM Zone 1

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
7	26	17	98.06	0.980208	0.894782
7	26	16	98.96	0.989204	0.880210
8	13	17	96.08	0.960416	0.878616
7	25	17	96.98	0.969412	0.809068
7	27	17	96.98	0.969412	0.809068
8	13	16	96.08	0.960416	0.777782
7	21	16	96.98	0.969412	0.672027
7	25	16	96.98	0.969412	0.672027
7	27	16	96.98	0.969412	0.672027
8	22	16	95.00	0.949620	0.635575
7	26	18	96.98	0.969412	0.598464
7	21	17	95.00	0.949620	0.541631
7	20	16	96.08	0.960416	0.534168
8	14	17	93.02	0.929828	0.501439
6	25	17	99.68	0.996401	0.471907
8	14	16	93.92	0.938824	0.464966
7	25	18	96.08	0.960416	0.454771
7	26	15	98.06	0.980208	0.450474
8	13	15	96.08	0.960416	0.410981
7	9	17	93.92	0.938824	0.370595
7	31	16	95.00	0.94962	0.363619
8	25	17	91.94	0.919032	0.33385
6	24	17	98.78	0.987405	0.333372
8	25	16	93.02	0.929828	0.327207
7	21	15	96.98	0.969412	0.290011
7	25	15	96.98	0.969412	0.290011
7	27	15	96.98	0.969412	0.290011
6	25	18	100.04	1	0.283900
8	13	18	93.02	0.929828	0.261315
6	24	16	99.32	0.992803	0.255159
6	25	16	99.32	0.992803	0.255159
7	1	17	93.02	0.929828	0.247844

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
7	20	17	93.02	0.929828	0.247844
7	24	17	93.02	0.929828	0.247844
7	28	17	93.02	0.929828	0.247844
7	31	17	93.02	0.929828	0.247844
7	24	16	93.92	0.938824	0.221617
8	12	17	91.04	0.910036	0.219034
8	22	17	91.04	0.910036	0.219034
8	7	16	91.94	0.919032	0.195066
8	12	16	91.94	0.919	0.195
7	21	18	93.92	0.939	0.172
7	27	18	93.92	0.939	0.172
6	26	17	97.34	0.973	0.165
8	14	15	93.92	0.939	0.148
7	18	17	91.94	0.919	0.141
7	19	17	91.94	0.919	0.141
7	1	16	93.02	0.930	0.137
7	9	16	93.02	0.930	0.137
7	28	16	93.02	0.930	0.137

Table 4-6: Highest Probability Summer Peak Hours Using TMY3 Data: TRM Zone 2

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
7	28	16	104.00	1	0.907820
7	28	17	102.92	0.989615	0.814721
7	28	15	102.92	0.989615	0.728393
7	12	17	102.02	0.980962	0.658955
8	16	15	100.94	0.970577	0.580281
8	16	16	100.04	0.961923	0.454025
7	28	18	102.02	0.980962	0.434022
7	11	17	100.94	0.970577	0.418685
8	17	15	100.04	0.961923	0.377912
7	10	16	100.94	0.970577	0.375504
7	11	16	100.94	0.970577	0.375504
7	12	16	100.94	0.970577	0.375504
8	17	16	99.68	0.958462	0.374406
8	17	17	99.32	0.955000	0.340336
7	12	15	100.94	0.970577	0.305196
7	27	15	100.94	0.970577	0.305196
8	16	17	98.96	0.951538	0.270767
7	27	17	100.04	0.961923	0.240394
7	27	16	100.04	0.961923	0.208991
8	8	15	98.96	0.951538	0.184638
8	9	15	98.96	0.951538	0.184638
7	10	15	100.04	0.961923	0.161783
7	11	15	100.04	0.961923	0.161783
8	17	18	98.96	0.951538	0.128439
8	8	16	98.06	0.942885	0.119879
7	10	17	98.96	0.951538	0.105521
8	7	15	98.06	0.942885	0.090497
8	10	15	98.06	0.942885	0.090497
8	13	15	98.06	0.942885	0.090497
8	24	15	98.06	0.942885	0.090497
8	9	16	97.70	0.939423	0.089275
8	7	16	97.34	0.935962	0.065899

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
8	10	16	97.34	0.935962	0.065899
8	16	18	98.06	0.942885	0.060815
8	8	17	96.98	0.932500	0.057330
7	9	17	98.06	0.942885	0.049281
8	7	17	96.80	0.930769	0.049062
8	10	17	96.80	0.930769	0.049062
7	11	18	98.96	0.951538	0.044726
7	27	18	98.96	0.951538	0.044726
7	9	16	98.06	0.943	0.041
8	3	17	96.44	0.927	0.036
8	6	17	96.44	0.927	0.036
8	3	15	96.98	0.933	0.036
8	6	15	96.98	0.933	0.036
8	11	15	96.98	0.933	0.036
8	14	15	96.98	0.933	0.036
8	3	16	96.62	0.929	0.035
8	6	16	96.62	0.929	0.035
7	13	15	98.06	0.943	0.031

Table 4-7: Highest Probability Summer Peak Hours Using TMY3 Data: TRM Zone 3

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
8	1	17	102.92	1	0.929380
8	2	17	102.92	1	0.929380
8	1	16	102.92	1	0.918911
8	2	16	102.02	0.991255	0.865717
8	3	16	100.04	0.972017	0.650841
8	2	18	102.02	0.991255	0.575415
8	4	17	98.96	0.961524	0.523849
8	12	17	98.96	0.961524	0.523849
8	4	16	98.96	0.961524	0.486478
8	5	16	98.96	0.961524	0.486478
8	29	16	98.96	0.961524	0.486478
8	1	15	100.94	0.980762	0.425501
8	2	15	100.94	0.980762	0.425501
8	4	15	100.94	0.980762	0.425501
8	1	18	100.94	0.980762	0.407850
8	9	17	98.06	0.952779	0.384956
8	11	17	98.06	0.952779	0.384956
8	29	17	98.06	0.952779	0.384956
8	10	16	98.06	0.952779	0.350206
8	12	16	98.06	0.952779	0.350206
8	10	17	96.80	0.940536	0.221282
8	9	16	96.98	0.942285	0.215012
8	3	15	98.96	0.961524	0.176375
8	8	17	96.08	0.933541	0.153237
8	27	17	96.08	0.933541	0.153237
8	28	17	96.08	0.933541	0.153237
8	11	16	96.08	0.933541	0.134819
8	26	16	96.08	0.933541	0.134819
8	12	15	98.06	0.952779	0.108599
8	29	15	98.06	0.952779	0.108599
8	19	17	95.00	0.923047	0.084225
8	26	17	95.00	0.923047	0.084225

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
8	8	16	95.00	0.923047	0.073383
8	27	16	95.00	0.923047	0.073383
8	28	16	95.00	0.923047	0.073383
8	10	15	96.98	0.942285	0.058306
8	4	18	96.98	0.942285	0.054444
8	12	18	96.98	0.942285	0.054444
8	15	17	93.92	0.912553	0.044655
8	20	17	93.92	0.912553	0.044655
8	15	16	93.92	0.913	0.039
8	19	16	93.92	0.913	0.039
8	20	16	93.92	0.913	0.039
8	9	15	96.08	0.934	0.034
8	27	15	96.08	0.934	0.034
8	28	15	96.08	0.934	0.034
7	14	17	96.98	0.942	0.034
8	11	18	96.08	0.934	0.032
8	28	18	96.08	0.934	0.032
8	5	17	93.02	0.904	0.026

Table 4-8: Highest Probability Summer Peak Hours Using TMY3 Data: TRM Zone 4

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
8	18	16	96.08	0.979808	0.380225
8	9	17	93.92	0.957781	0.305170
8	9	16	95.00	0.968795	0.302115
8	7	17	93.02	0.948603	0.247248
8	10	17	93.02	0.948603	0.247248
8	15	17	93.02	0.948603	0.247248
8	16	17	93.02	0.948603	0.247248
8	19	17	93.02	0.948603	0.247248
8	6	16	93.92	0.957781	0.233993
8	7	16	93.92	0.957781	0.233993
8	10	16	93.92	0.957781	0.233993
8	15	16	93.92	0.957781	0.233993
8	16	16	93.92	0.957781	0.233993
8	17	16	93.92	0.957781	0.233993
8	19	16	93.92	0.957781	0.233993
6	7	17	96.08	0.979808	0.231957
8	9	15	96.08	0.979808	0.201074
8	4	17	91.94	0.937589	0.188163
8	5	17	91.94	0.937589	0.188163
8	6	17	91.94	0.937589	0.188163
8	8	17	91.94	0.937589	0.188163
8	11	17	91.94	0.937589	0.188163
8	17	17	91.94	0.937589	0.188163
8	18	17	91.94	0.937589	0.188163
8	27	17	91.94	0.937589	0.188163
8	4	16	93.02	0.948603	0.185965
8	5	16	93.02	0.948603	0.185965
8	11	16	93.02	0.948603	0.185965
8	27	16	93.02	0.948603	0.185965
6	7	16	96.08	0.979808	0.173590
8	16	15	95.00	0.968795	0.150812
8	18	15	95.00	0.968795	0.150812

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
8	1	17	91.04	0.928411	0.147727
8	2	17	91.04	0.928411	0.147727
8	3	17	91.04	0.928411	0.147727
8	12	17	91.04	0.928411	0.147727
8	13	17	91.04	0.928411	0.147727
8	21	17	91.04	0.928411	0.147727
8	22	17	91.04	0.928411	0.147727
8	31	17	91.04	0.928411	0.147727
8	2	16	91.94	0.938	0.139
8	3	16	91.94	0.938	0.139
8	12	16	91.94	0.938	0.139
8	13	16	91.94	0.938	0.139
8	22	16	91.94	0.938	0.139
8	31	16	91.94	0.938	0.139
9	10	17	93.92	0.958	0.131
8	4	15	93.92	0.958	0.111
8	7	15	93.92	0.958	0.111
8	10	15	93.92	0.958	0.111

Table 4-9: Highest Probability Summer Peak Hours Using TMY3 Data: TRM Zone 5

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
8	7	16	98.96	0.970006	0.725586
7	2	15	100.04	0.980592	0.717902
7	3	14	100.04	0.980592	0.702518
8	6	15	96.98	0.950598	0.678213
8	8	15	96.98	0.950598	0.678213
7	2	16	100.94	0.989414	0.654366
7	3	16	100.94	0.989414	0.654366
6	15	15	100.94	0.989414	0.610964
7	1	15	98.96	0.970006	0.601451
7	3	15	98.96	0.970006	0.601451
6	14	14	100.94	0.989414	0.593054
7	1	14	98.96	0.970006	0.583402
8	4	15	96.08	0.941776	0.576910
6	2	16	102.02	1	0.560372
7	1	16	100.04	0.980592	0.550531
6	2	15	100.04	0.980592	0.503974
6	14	15	100.04	0.980592	0.503974
8	4	16	96.98	0.950598	0.503578
8	6	16	96.98	0.950598	0.503578
7	26	15	98.06	0.961184	0.494011
6	2	14	100.04	0.980592	0.485289
6	15	14	100.04	0.980592	0.485289
7	2	14	98.06	0.961184	0.475341
7	26	14	98.06	0.961184	0.475341
8	7	15	95.00	0.931190	0.447083
8	11	15	95.00	0.931190	0.447083
8	27	15	95.00	0.931190	0.447083
6	14	16	100.94	0.989414	0.430480
8	4	14	95.00	0.931190	0.428684
8	6	14	95.00	0.931190	0.428684
8	7	14	95.00	0.931190	0.428684
6	7	15	98.96	0.970006	0.375975

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Maximum Temperature	Relative Probability PDPF
7	6	15	96.98	0.950598	0.366672
6	5	16	100.04	0.980592	0.328415
6	15	16	100.04	0.980592	0.328415
8	26	15	93.92	0.920604	0.324093
7	6	16	98.06	0.961184	0.319686
8	8	14	93.92	0.920604	0.307936
8	11	14	93.92	0.920604	0.307936
8	27	14	93.92	0.920604	0.307936
6	1	15	98.06	0.961	0.280
6	5	15	98.06	0.961	0.280
6	6	15	98.06	0.961	0.280
6	18	15	98.06	0.961	0.280
8	27	16	95.00	0.931	0.280
6	5	14	98.06	0.961	0.266
6	7	14	98.06	0.961	0.266
7	6	14	96.08	0.942	0.258
8	10	15	93.02	0.912	0.237
6	6	16	98.96	0.970	0.225

Table 4-10: Highest Probability Winter Peak Hours Using TMY3 Data: TRM Zone 1

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
12	16	20	14.54	7.56	0.721729
2	16	8	6.98	0	0.708012
12	16	21	12.92	5.94	0.701978
12	16	19	16.34	9.36	0.556675
2	14	20	21.92	14.94	0.486565
2	14	19	21.92	14.94	0.398140
2	14	21	21.92	14.94	0.382398
12	16	8	11.66	4.68	0.363779
12	30	21	19.94	12.96	0.361170
12	16	22	13.28	6.30	0.344873
12	30	20	22.64	15.66	0.333252
1	16	20	21.74	14.76	0.280425
12	16	9	10.04	3.06	0.254420
2	17	8	17.06	10.08	0.238066
12	16	10	12.38	5.40	0.229522
1	16	21	21.02	14.04	0.227651
2	14	8	17.96	10.98	0.206482
2	15	8	17.96	10.98	0.206482
2	16	9	14.00	7.02	0.199925
1	16	19	22.28	15.30	0.195983
12	12	21	24.08	17.10	0.195940
12	12	20	26.42	19.44	0.188175
2	16	20	28.94	21.96	0.185310
2	28	20	28.94	21.96	0.185310
2	3	21	26.96	19.98	0.181842
2	16	21	26.96	19.98	0.181842
12	29	21	24.98	18.00	0.168707
1	11	20	24.98	18.00	0.167845
12	30	19	25.34	18.36	0.167724
1	11	21	23.00	16.02	0.164638
2	1	20	30.02	23.04	0.154423
2	3	20	30.02	23.04	0.154423

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
2	15	20	30.02	23.04	0.154423
1	30	8	15.26	8.28	0.151537
2	1	21	28.04	21.06	0.151426
2	28	21	28.04	21.06	0.151426
12	17	8	17.60	10.62	0.145980
12	11	20	28.04	21.06	0.142922
12	29	20	28.04	21.06	0.142922
1	29	21	24.08	17.10	0.136619
1	30	21	24.08	17.100	0.137
2	14	22	21.92	14.940	0.130
12	30	22	19.58	12.600	0.128
12	11	21	26.96	19.980	0.119
12	14	21	26.96	19.980	0.119
1	30	20	27.14	20.160	0.115
12	14	20	29.30	22.320	0.114
2	15	19	30.02	23.040	0.113
2	28	19	30.02	23.040	0.113
2	14	10	19.04	12.060	0.112

Table 4-11: Highest Probability Winter Peak Hours Using TMY3 Data: TRM Zone 2

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
2	11	8	12.02	1.08	0.916726
2	11	7	10.94	0	0.742601
2	10	20	19.04	8.10	0.717078
2	10	21	17.96	7.02	0.708888
2	10	19	19.94	9.00	0.615930
2	11	21	19.04	8.10	0.568022
2	11	9	14.00	3.06	0.516421
2	11	20	21.02	10.08	0.450242
2	11	19	21.92	10.98	0.341324
2	10	22	17.06	6.12	0.316268
2	11	10	15.08	4.14	0.294199
1	12	8	21.92	10.98	0.093075
2	11	22	19.94	9.00	0.082097
12	31	20	26.06	15.12	0.065604
12	31	21	24.98	14.04	0.063193
12	31	19	26.96	16.02	0.042535
2	12	8	21.92	10.98	0.037332
1	17	8	24.08	13.14	0.029056
12	31	22	24.26	13.32	0.011431
2	2	8	24.08	13.14	0.011181
12	30	20	29.30	18.36	0.010934
12	30	19	29.66	18.72	0.009429
1	12	7	23.00	12.06	0.007781
12	30	21	28.94	18.00	0.006994
12	9	8	25.70	14.76	0.006776
2	3	8	24.98	14.04	0.006721
12	7	20	30.38	19.44	0.005934
12	8	20	30.38	19.44	0.005934
12	9	20	30.38	19.44	0.005934
12	7	19	30.56	19.62	0.005664
12	8	19	30.56	19.62	0.005664
12	9	19	30.56	19.62	0.005664

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
12	8	8	26.06	15.12	0.005525
2	12	7	21.92	10.98	0.005458
1	17	7	24.08	13.14	0.004217
12	7	21	30.02	19.08	0.003789
12	8	21	30.02	19.08	0.003789
12	9	21	30.02	19.08	0.003789
1	13	8	28.04	17.10	0.003115
1	16	8	28.04	17.10	0.003115
12	3	20	31.64	20.700	0.003
1	12	9	26.06	15.120	0.003
12	10	8	27.32	16.380	0.003
12	3	21	30.92	19.980	0.002
1	12	21	32.00	21.060	0.002
12	3	19	32.36	21.420	0.002
1	4	8	28.94	18.000	0.002
12	10	7	24.62	13.680	0.002
12	8	9	26.06	15.120	0.002
12	9	9	26.06	15.120	0.002

Table 4-12: Highest Probability Winter Peak Hours Using TMY3 Data: TRM Zone 3

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
2	11	20	30.92	9.90	0.502885
2	11	8	21.02	0	0.464756
2	11	7	21.02	0	0.437624
2	11	9	21.02	0	0.405064
2	11	21	30.02	9.00	0.368255
2	11	10	24.08	3.06	0.355696
2	11	19	35.06	14.04	0.277598
2	12	8	24.08	3.06	0.200333
2	12	7	24.08	3.06	0.183350
2	11	22	28.94	7.92	0.164428
2	3	7	26.06	5.04	0.091280
1	22	21	35.96	14.94	0.091131
1	23	8	28.04	7.02	0.087855
1	23	7	28.04	7.02	0.079459
1	11	20	39.02	18.00	0.067479
1	18	20	39.02	18.00	0.067479
1	18	19	41.00	19.98	0.062001
1	11	21	37.04	16.02	0.060733
2	12	9	26.96	5.94	0.057470
12	20	19	39.92	18.90	0.054753
1	18	21	37.94	16.92	0.042934
1	11	8	30.02	9.00	0.041312
1	19	8	30.02	9.00	0.041312
1	19	7	30.02	9.00	0.037183
2	12	20	39.02	18.00	0.036307
2	12	10	30.92	9.90	0.033164
1	11	9	30.02	9.00	0.032685
2	12	21	37.04	16.02	0.032568
1	4	20	41.00	19.98	0.031360
1	21	20	41.00	19.98	0.031360
1	22	20	41.00	19.98	0.031360
1	22	22	35.06	14.04	0.030503

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
12	20	20	39.92	18.90	0.027589
1	5	7	30.92	9.90	0.026094
1	11	7	30.92	9.90	0.026094
2	2	20	39.92	18.90	0.025473
2	2	22	33.98	12.96	0.024772
12	25	8	30.02	9.00	0.023773
1	19	9	30.92	9.90	0.022906
2	3	8	30.02	9.00	0.021943
2	5	19	42.08	21.060	0.022
2	12	19	42.08	21.060	0.022
1	11	22	35.96	14.940	0.021
1	19	20	42.08	21.060	0.020
2	15	7	30.02	9.000	0.020
1	4	21	39.92	18.900	0.020
1	4	19	44.06	23.040	0.019
1	11	19	44.06	23.040	0.019
1	20	19	44.06	23.040	0.019
1	21	19	44.06	23.040	0.019

Table 4-13: Highest Probability Winter Peak Hours Using TMY3 Data: TRM Zone 4

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
2	11	10	28.94	2.88	0.474019
2	11	20	35.96	9.90	0.467055
1	17	20	39.02	12.96	0.443391
2	11	21	35.06	9.00	0.408858
2	11	8	26.06	0	0.404184
2	11	9	26.96	0.90	0.397264
1	17	19	39.02	12.96	0.357624
2	11	7	26.96	0.90	0.311355
1	19	20	41.00	14.94	0.294982
1	17	21	39.92	13.86	0.259323
1	19	21	39.92	13.86	0.259323
12	25	21	39.56	13.50	0.234162
2	11	22	35.06	9.00	0.227514
1	19	19	41.00	14.94	0.226254
12	25	20	41.36	15.30	0.224276
12	25	22	37.94	11.88	0.180665
12	20	20	42.62	16.56	0.161018
12	25	10	35.96	9.90	0.149340
2	11	19	39.92	13.86	0.144545
12	20	21	42.44	16.38	0.107021
12	20	19	42.98	16.92	0.106593
12	25	19	42.98	16.92	0.106593
1	18	20	44.96	18.90	0.103484
1	17	22	41.00	14.94	0.094969
1	19	22	41.00	14.94	0.094969
2	12	10	35.96	9.90	0.084176
12	21	20	44.96	18.90	0.082289
1	20	9	35.96	9.90	0.079878
1	19	10	39.02	12.96	0.077104
1	12	20	46.04	19.98	0.075138
12	25	9	35.60	9.54	0.070471
2	12	8	33.08	7.02	0.064709

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
1	12	21	44.96	18.90	0.063655
1	18	21	44.96	18.90	0.063655
2	12	9	33.98	7.92	0.062986
1	20	8	35.96	9.90	0.062511
12	21	10	39.02	12.96	0.060945
2	2	20	44.06	18.00	0.059184
12	21	19	44.96	18.90	0.058971
12	25	7	35.06	9.00	0.058372
12	26	7	35.06	9.000	0.058
2	12	7	33.08	7.020	0.058
12	25	8	35.42	9.360	0.058
1	20	7	35.96	9.900	0.056
12	20	22	42.08	16.020	0.054
12	21	21	44.96	18.900	0.050
2	2	21	42.98	16.920	0.050
1	19	9	37.94	11.880	0.044
1	18	19	46.94	20.880	0.041
1	15	8	37.94	11.880	0.034

Table 4-14: Highest Probability Winter Peak Hours Using TMY3 Data: TRM Zone 5

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
12	26	19	35.06	13.14	0.678814
12	26	20	35.96	14.04	0.592910
12	2	19	41.00	19.08	0.509178
12	18	19	41.00	19.08	0.509178
12	19	19	41.00	19.08	0.509178
12	27	19	41.00	19.08	0.509178
12	21	19	42.08	20.16	0.476850
12	28	19	42.08	20.16	0.476850
12	2	20	39.92	18.00	0.475420
12	18	20	39.92	18.00	0.475420
12	19	20	39.92	18.00	0.475420
12	27	20	39.92	18.00	0.475420
12	3	19	42.98	21.06	0.450045
12	30	19	42.98	21.06	0.450045
12	28	20	41.00	19.08	0.443299
12	29	20	41.00	19.08	0.443299
12	30	20	41.00	19.08	0.443299
12	26	21	33.98	12.06	0.419388
12	12	19	44.06	22.14	0.418272
12	14	19	44.06	22.14	0.418272
12	29	19	44.06	22.14	0.418272
12	3	20	42.08	20.16	0.411645
12	31	20	42.08	20.16	0.411645
12	4	19	44.96	23.04	0.392291
12	4	20	42.98	21.06	0.385803
12	12	20	42.98	21.06	0.385803
12	14	20	42.98	21.06	0.385803
12	16	20	42.98	21.06	0.385803
12	21	20	42.98	21.06	0.385803
12	29	21	35.96	14.04	0.362971
12	31	19	46.04	24.12	0.361912
12	1	20	44.06	22.14	0.355632

Month	Day	Hour Ending (CDT)	Hourly Temperature	Relative Minimum Temperature	Relative Probability PDPF
12	1	19	46.94	25.02	0.337401
12	6	19	46.94	25.02	0.337401
12	16	19	46.94	25.02	0.337401
12	25	19	46.94	25.02	0.337401
12	6	20	44.96	23.04	0.331326
12	3	21	37.94	16.02	0.310091
12	28	21	37.94	16.02	0.310091
12	20	20	46.04	24.12	0.303312
12	11	19	48.92	27.000	0.287
12	2	21	39.02	17.100	0.283
12	18	21	39.02	17.100	0.283
12	19	21	39.02	17.100	0.283
12	24	20	46.94	25.020	0.281
12	25	20	46.94	25.020	0.281
12	26	18	35.96	14.040	0.280
12	27	21	39.92	18.000	0.262
1	26	19	37.94	16.020	0.256
2	8	19	41.00	19.080	0.254

Table 4-15 through Table 4-24 provide Peak Hour Probability Factors (PHPF's) developed using TMY3 Data for loads that vary by peak hour.

Table 4-15: TRM Climate Zone 1 Hour Ending Relative Probability of Summer Peak

Hour Ending	Relative Probability PDPF
16	0.425
17	0.422
18	0.084
15	0.069

Table 4-16: TRM Climate Zone 2 Hour Ending Relative Probability of Summer Peak

Hour Ending	Relative Probability PDPF
16	0.352
17	0.314
15	0.284
18	0.050

Table 4-17: TRM Climate Zone 3 Hour Ending Relative Probability of Summer Peak

Hour Ending	Relative Probability PDPF
16	0.421
17	0.372
15	0.117
18	0.090

Table 4-18: TRM Climate Zone 4 Hour Ending Relative Probability of Summer Peak

Hour Ending	Relative Probability PDPF
17	0.481
16	0.478
15	0.041

Table 4-19: TRM Climate Zone 5 Hour Ending Relative Probability of Summer Peak

Hour Ending	Relative Probability PDPF
15	0.497
16	0.346
14	0.157

Table 4-20: TRM Climate Zone 1 Hour Ending Relative Probability of Winter Peak

Hour Ending	Relative Probability PDPF
20	0.246
8	0.233
21	0.226
19	0.156
9	0.061
22	0.047
10	0.031

Table 4-21: TRM Climate Zone 2 Hour Ending Relative Probability of Winter Peak

Hour Ending	Relative Probability PDPF
21	0.202
20	0.186
8	0.164
19	0.151
7	0.112
9	0.078
22	0.062
10	0.044

Table 4-22: TRM Climate Zone 3 Hour Ending Relative Probability of Winter Peak

Hour Ending	Relative Probability PDPF
7	0.194
8	0.185
20	0.156
21	0.127
9	0.113
19	0.097
10	0.087
22	0.040

Table 4-23: TRM Climate Zone 4 Hour Ending Relative Probability of Winter Peak

Hour Ending	Relative Probability PDPF
20	0.278
21	0.221
19	0.127
10	0.109
22	0.071
8	0.071
9	0.069
7	0.054

Table 4-24: TRM Climate Zone 5 Hour Ending Relative Probability of Winter Peak

Hour Ending	Relative Probability PDPF
19	0.560
20	0.396
21	0.043

Table 4-25 through Table 4-34 provide PDPF's for each peak month-hour developed using TMY3 Data for use to estimate peak demand impacts for load shapes that vary by month, day, and hour.

Table 4-25: TRM Climate Zone 1 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
7	16	0.274
7	17	0.274
8	16	0.150
8	17	0.110
7	18	0.084
6	17	0.038
7	15	0.036
8	15	0.033

Table 4-26: TRM Climate Zone 2 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
7	16	0.257
7	17	0.244
7	15	0.153
8	15	0.131
8	16	0.095
8	17	0.070
7	18	0.050

Table 4-27: TRM Climate Zone 3 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
8	16	0.421
8	17	0.372
8	15	0.117
8	18	0.090

Table 4-28: TRM Climate Zone 4 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
8	16	0.478
8	17	0.433
6	17	0.048
8	15	0.041

Table 4-29: TRM Climate Zone 5 Relative Probability of Summer Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
7	15	0.201
8	15	0.161
7	16	0.155
8	16	0.144
6	15	0.135
7	14	0.107
6	14	0.049
6	16	0.047

Table 4-30: TRM Climate Zone 1 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
2	8	0.184
12	21	0.144
12	20	0.143
12	19	0.075
2	20	0.066
2	19	0.054
2	21	0.052
12	8	0.049
12	22	0.047
1	20	0.038
12	9	0.034
12	10	0.031
1	21	0.031
2	9	0.027
1	19	0.026

Table 4-31: TRM Climate Zone 2 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
2	21	0.193
2	20	0.176
2	8	0.146
2	19	0.145
2	7	0.112
2	9	0.078
2	22	0.060
2	10	0.044
1	8	0.018
12	20	0.010
12	21	0.010
12	19	0.006
12	22	0.002

Table 4-32: TRM Climate Zone 3 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
2	7	0.175
2	8	0.163
2	20	0.123
2	9	0.113
2	21	0.090
2	10	0.087
2	19	0.068
2	22	0.040
1	21	0.037
1	20	0.033
1	8	0.022
1	7	0.019
1	19	0.015
12	19	0.013

Table 4-33: TRM Climate Zone 4 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
1	20	0.129
1	19	0.102
1	21	0.090
2	10	0.083
2	20	0.081
2	21	0.071
2	8	0.071
2	9	0.069
12	20	0.067
12	21	0.060
2	7	0.054
2	22	0.040
12	22	0.032
12	10	0.026
2	19	0.025

Table 4-34: TRM Climate Zone 5 Relative Probability of Winter Peak for Month-Hour Combinations

Month	Hour	Relative Probability PDPF
12	19	0.560
12	20	0.396
12	21	0.043

5. STRUCTURE AND CONTENT

This section provides information on measure codes and the TRM measure overviews to assist the reader in using the information in Volumes 2 through 4 of the TRM.

5.1 MEASURE CODES

The EM&V team has developed a Measure ID code to allow users to quickly access the information they need for the market sector, end-use, and measure description. By looking at the measure code, the user can quickly identify key aspects of the measure, even if they cannot determine energy savings from the code. Due to differences in commercial and residential measures, the construction of the measure code differs slightly in each sector. The commercial codes stay at a higher level than the residential codes. Table 5-1 through Table 5-4 describe the encoding process used for the Measure ID.

Table 5-1: Residential TRM Measure ID Creation

Sequence	Category	ID	Description
1	Sector	R	Residential
2	Measure Category	LT	Lighting
		HV	HVAC
		BE	Building envelope
		WH	Domestic water heating
		AP	Appliances
		HS	Whole-house
		RN	Renewable
		LM	Demand response
3	Measure Code	XX	Per specific measure (See Table 5-3)

Table 5-2: Nonresidential TRM Measure ID Creation

Sequence	Category	ID	Description
1	Sector	NR	Nonresidential
2	Measure Category	LT	Lighting
		HV	HVAC
		BE	Building envelope
		FS	Food service
		RF	Refrigeration
		MS	Miscellaneous
		RN	Renewable
		LM	Demand response
3	Measure Code	XX	Per specific measure (See Table 5-4)

Table 5-3: Residential and Non-Residential Measure Code Mapping

Sector	Measure Category	Measure Description	Measure Code
Residential	LT	Compact fluorescent lamps	CF
	HV	Central AC	AC
	HV	Window AC	WA
	HV	Ground source heat pump	GH
	HV	Central heat pump	HP
	HV	Split system and single-package heat pumps between 65,000 BTU/H and 240,000 BTU/H	PS
	HV	Split System and Single-Package Air Conditioners between 65,000 BTU/H and 240,000 BTU/H	SA
	HV	Duct efficiency improvement	DE
	HV	Air conditioning tune-up	TU
	BE	Air infiltration	AI
	BE	Ceiling insulation	CI
	BE	Wall insulation	WI
	BE	Floor insulation	FI
	BE	ENERGY STAR® windows	EW
	BE	Solar screens	SC
	WH	Faucet aerators	FA
	WH	Low-flow showerheads	SH
	WH	Water heater jackets	WJ
	WH	Water heater pipe insulation	WP
	WH	Heat pump water heater	HW
	WH	Water heater replacement - high efficiency	WH
	WH	Water heater replacement - solar water heating	WS
	WH	Showerhead thermostatic restrictor valve	TV
	WH	Tub spout and showerhead thermostatic restrictor valve	TS
	AP	ENERGY STAR® ceiling fans	FN
	AP	ENERGY STAR® clothes washer	CW
	AP	ENERGY STAR® dishwasher	DW
	AP	ENERGY STAR® refrigerator	RF
	AP	ENERGY STAR® pool pumps	PP
	HS	New homes	NH
	RN	Solar photovoltaic (PV)	PV
	RN	Solar shingles	SS
	LM	Direct load control switches installed on outdoor compressor units	OC
	LM	Direct load control switches installed on swimming pool pump motors	SP
	LM	Load curtailment	LM
	AP	Appliance recycling	RR

Table 5-4: Non-Residential Measure Code Mapping

Sector	Measure Category	Measure Description	Measure Code
Non-Residential	LT	lamps and fixtures	LF
	LT	lighting controls	LC
	HV	Package and Split-System HVAC Units (AC and Heat Pumps)	PS
	HV	Package Terminal Units and Room Air Conditioners (AC and Heat Pumps)	PT
	HV	Chillers	CH
	HV	VFDs on AHU supply fans	VF
	HV	Air conditioning tune-up	TU
	HV	Ground source heat pump	GH
	HV	Variable refrigerant flow systems	VR
	HV	Condenser air evaporative pre-cooling	EP
	BE	Cool roof	CR
	BE	Window films and solar screens	WF
	FS	ENERGY STAR® commercial dishwashers	DW
	FS	ENERGY STAR® commercial electric hot food holding cabinets	HC
	FS	ENERGY STAR® electric steam cookers	SC
	FS	ENERGY STAR® kitchen electric fryers	EF
	FS	High efficiency electric combination ovens	CO
	FS	High efficiency electric convection ovens	CV
	FS	Pre-rinse spray valves	SV
	RF	Door heater controls	DC
	RF	ECM evaporator fan motors	FM
	RF	Evaporator fan controls	FC
	RF	Electronic defrost control	DF
	RF	Night covers for open refrigerated cases	RC
	RF	High-efficiency solid & glass door reach-in cases	RI
	RF	Strip curtains for walk-in cooler/freezer	SC
	RF	Low/no anti-sweat heat glass doors (zero energy glass doors)	ZE
	MS	Vending machine controllers	VC
	MS	Lodging guest room occupancy sensor controls	GR
	MS	Pump off controllers	PC
	MS	Behavioral change	BC
	RN	Solar photovoltaics	PV
	MS	ENERGY STAR® Pool Pumps	PP
	MS	Air compressors less than 75hp	CA
	RN	Solar shingles	SS
	LM	Load curtailment	LM

5.2 MEASURE OVERVIEW LAYOUT

A “measure overview” is the basic structure that is used to characterize every measure in the TRM. There is one measure overview section per TRM measure, and it encapsulates all the information needed to characterize the measure, calculate the deemed savings, document the sources used for those calculations, track changes made to the measure overview, and record any issues and recommendations for improving the approach. Note that although the basic template structure described here is generally used for all measures, there are some measures that require an adaptation or modification. Furthermore, there are some sections of the general template that are not applicable to specific measures, in which case they are not used for the measure overview. Each measure overview contains the following sections:

Sector and TRM measure name. At the top of every measure overview section, the sector (residential or nonresidential) and TRM measure name are presented. The sector, end use, and TRM measure name are also shown in the page footer, to make scrolling through the TRM easier. Without the footer information, it is easy to get lost while scrolling on a specific measure, since every section uses the same layout structure (headers, etc.).

Measure overview summary. This section, which appears just below the measure name, contains a bulleted list that is a concise characterization of the measure. It starts with the Measure ID, as previously defined, and also includes characteristics such as the market sector, measure category, applicable building types, fuels affected, decision/action types (e.g., retrofit, replace-on-burnout), program delivery method, deemed savings type (value or calculated), and the savings methodology (e.g., engineering estimation, calculator, building simulation, billing analysis).

Measure description. This section provides a general description of the measure, the eligibility criteria, the *baseline condition* (e.g., efficiency level, technology, performance), and the *high-efficiency condition*. Any special conditions, scenarios, or required technology/performance certifications or relevant Codes and Standards are also described in this section.

Energy and demand savings methodology. This section of the measure overview presents and describes the parameters, equations, assumptions, and reference sources that are used for the energy and demand savings for the measure. An extensive set of subsections is used to describe and illustrate the details:

- **Savings algorithms and input variables**. Provide the actual equations and parameters that are used for the savings calculations and provide an explanation and references for all. This section would also contain any look-up tables of stipulated values that are used for the calculations.
- **Deemed energy and demand savings tables.** Presents the tabulated deemed energy and demand savings values developed using the algorithms and look-up table parameters. If site-specific inputs or equipment specifications are required, then a statement to that extent rather than result tables will be listed in this section.
- **Claimed peak demand savings.** This section is a brief description of the current and prospective peak demand values that will be used, coincidence factors, and the basis used to derive those values. If the basis of the current peak demand value is not known, then that will be noted, and the team will follow up with the utilities, implementers or others to determine the basis.

- **Additional calculators and tools.** If a calculator or other tool is available and typically used for calculating measure savings, then that tool and/or tools would be briefly described in this section. If a tool is not used, then "NA" would be recorded for this section, or it will be excluded from the measure overview.
- **Measure life and lifetime savings.** This section notes the EUL and its source and describes how lifetime savings should be calculated. For a subset of HVAC retrofit measures, assumptions for early retirement would also be discussed in this section. For example, for Commercial HVAC early retirement, the measure life does not necessarily equal the EUL.

Additional parameters. This section is used for unique, measure-specific parameters that impact the savings calculations, but are not currently included in the calculation algorithms. This section will only appear in the measure overview for those measures that require additional parameters. Examples include In-Service Rate and Non-Energy Benefits Impact, which are targeted as future residential parameters.

Program tracking data and evaluation requirements. This section specifies the recommended list of primary inputs and contextual data needed for evaluation and proper application of the savings. For example, the application of interactive HVAC factors should, as a minimum, require tracking the space conditioning type in which a lighting system is used (air conditioned, or low/medium temperature refrigerated), otherwise the interactive HVAC savings should not be applied. As there are negative heating impacts, the heating system fuel type (electric or gas) should also be recorded.

References and efficiency standards. All references and citations are summarized in this section.

- **Petitions and rulings.** Provides a running list of the relevant petitions and rulings related to deemed savings for the specific measure.
- **Relevant standards and reference sources.** Provides a bulleted list of the applicable energy-efficiency standards (Federal Appliance Standards, ASHRAE 90.1, etc.), associated links and its relevance to the measure. Also lists all sources used for the development of inputs to savings, values, and deemed savings calculations.

Document revision history. This table is used to track the revision history of the measure overview. An example is shown in Table 5-5.

Table 5-5: Nonresidential [Measure Name] Revision History

TRM Version	Date	Description of Change
v1.0	11/25/2013	TRM V1.0 origin
v2.1	1/30/2015	Updated to most recent ENERGY STAR® standard
v3.0	4/10/2015	Update of savings method to allow for….
v4.0	10/10/2016	No revision.

APPENDIX A: GLOSSARY

P.U.C. SUBST. R. 25.181, relating to Energy Efficiency Goal (Project No. 39674), contains definitions in section (c). Below, we provide additional definitions relevant to the TRM as well as definitions from § 25.181 denoted with a *****.

Accuracy. A concept that refers to the relationship between the true value of a variable and an estimate of the value. The term can also be used in reference to a model or a set of measured data, or to describe a measuring instrument's capability.

ASHRAE Guideline 14. American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Guideline 14, *2002 Measurement of Energy and Demand Savings* (www.ashrae.org).

Benchmarking. A process that compares the energy, emissions, and other resource-related conditions of a facility against industry best practices or other benchmarks such as average per square foot energy consumption of similar buildings in the same city or climate zone.

Bias. The extent to which a measurement or a sampling or analytic method systematically underestimates or overestimates a value. Some examples of types of bias include engineering model bias; meter bias; sensor placement bias; inadequate or inappropriate estimates of what would have happened absent a program or measure installation; a sample that is unrepresentative of a population; and selection of other variables in an analysis that are too correlated with the savings variable (or each other) in explaining the dependent variable (such as consumption).

Billing analysis. A term used to define either (1) a specific measurement and verification (M&V) approach used to estimate project savings; or (2) any analytic methodology used to determine project or program energy savings based on the use of the energy consumption data contained in consumer billing data. It compares billing data from program participant(s) over a period of time before the energy-efficient measures are installed at customer site(s) to billing data for a comparable period of time afterward. If used to describe an M&V approach, it is equivalent to IPMVP Option C, Whole Building Analysis. If used to describe an evaluation approach, it is comparable to the large-scale data analysis approach.

Building energy simulation model. Computer models based on physical engineering principals and/or standards used to estimate energy use and/or savings. These models usually incorporate site-specific data on customers and physical systems, such as square footage, weather, surface orientations, elevations, space volumes, construction materials, equipment use, lighting, and building occupancy. Building simulation models can usually account for interactive effects between end uses (e.g., lighting and HVAC), part-load efficiencies, and changes in external and internal heat gains/losses. Examples of building simulation models include DOE-2, Energy Plus, and Carrier HAP.

Calendar year for peak demand. The calendar year applied to the 8760 TMY3 data. The choice of calendar year determines the weekday/weekend and holiday classification for each day.

Calibration. In economic, planning, or engineering modeling, the process of adjusting the components of the model to reflect reality as closely as possible to prepare for the model's use in future applications. The term also applies to the process whereby metering and measurement equipment is periodically adjusted to maintain industry measurement standards.

Claimed savings. Values reported by an electric utility after the energy efficiency activities have been completed, but prior to the time an independent, third-party evaluation of the savings is performed. As with projected savings estimates, these values may utilize results of prior evaluations and/or values in technical reference manuals. However, they are adjusted from projected savings estimates by correcting for any known data errors and actual installation rates and may also be adjusted with revised values for factors such as per-unit savings values, operating hours, and savings persistence rates. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

Coincident demand. The demand of a device, circuit, or building that occurs at the same time as the peak demand of a utility's system load or at the same time as some other peak of interest, such as building or facility peak demand. The peak of interest should be specified (e.g., "demand coincident with the utility system peak"). The following are examples of peak demand:

- Demand coincident with utility system peak load
- Demand coincident with independent system operator/regional transmission organization summer or winter peak or according to performance hours defined by wholesale capacity markets
- Demand coincident with high electricity demand days

Coincidence factors (CF).[19] Coincidence factors are the fractions of the rated load reductions that occur during each of the peak demand windows. They are the ratio of the demand reductions during the coincident window to the connected load reductions. Other issues such as diversity and load factor are automatically accounted for, and only the coincidence factor will be necessary to determine coincident demand reductions from readily observable equipment nameplate (rated) information. In other words, coincident demand reduction will simply be the product of the coincidence factor and the connected equipment load kW reduction.

Common practice. The predominant technology(ies) implemented or practice(s) undertaken in a particular region or sector. Common practices can be used to define a baseline.

Cooling degree days. See *degree days*.

Custom program. An energy efficiency program intended to provide efficiency solutions to unique situations not amenable to common or prescriptive solutions. Each custom project is examined for its individual characteristics, savings opportunities, efficiency solutions, and often, customer incentives.

Database for energy-efficient resources (DEER). A California database designed to provide publicly available estimates of energy and peak demand savings values, measure costs, and effective useful life (www.deeresources.com).

Decision/action types. This refers to the type of equipment installation that is performed. Acceptable values include Retrofit (RET), New Construction (NC), Early Retirement (ER), and Replace-on-Burnout (ROB). The definition of each of these values can be found in this glossary.

[19] Source: Petition #39146, page 15.

***Deemed savings calculation.** An industry-wide engineering algorithm used to calculate energy and/or demand savings of the installed energy efficiency measure that has been developed from common practice that is widely considered acceptable for the measure and purpose and is applicable to the situation being evaluated. May include stipulated assumptions for one or more parameters in the algorithm, but typically requires some data associated with actual installed measure. An electric utility may use the calculation with documented measure-specific assumptions, instead of energy and peak demand savings determined through measurement and verification activities or the use of deemed savings. (§ 25.181 (c) (7))

***Deemed savings value.** An estimate of energy or demand savings for a single unit of an installed energy efficiency measure that has been developed from data sources and analytical methods that are widely considered acceptable for the measure and purpose and is applicable to the situation being evaluated. An electric utility may use deemed savings values instead of energy and peak demand savings determined through measurement and verification activities. (§ 25.181 (c) (8))

Degree days. For any individual day, an indication of how far that day's average temperature departed from a fixed temperature, usually 18.3°C/65°F. Heating degree days, which measure heating energy needs, quantify how far the average temperature fell below 65°F. Similarly, cooling degree days, which measure cooling energy needs, quantify how far the temperature averaged above 65°F. In both cases, smaller values represent less energy consumption however, values below 0 are set equal to 0, because energy demand cannot be negative. Furthermore, because energy demand is cumulative, degree day totals for periods exceeding one day are simply the sum of each individual day's degree days total. Degree days are used in calculations of heating and cooling energy consumption and in evaluation regression analyses to adjust for differences in heating and cooling requirements between baseline and project scenarios.

***Demand savings.** A quantifiable reduction in demand. (§ 25.181 (c) (10))

Demand-side management (DSM). Strategies used to manage energy demand, including energy efficiency, load management, fuel substitution, and load building.

Direct install program. An energy efficiency program design strategy involving the direct installation of measures in customer premises by a contractor sponsored by the program. Such programs generally involve one-for-one replacement of existing equipment with more efficient equipment and may include a customer rebate.

Diversity. That characteristic of a variety of electric loads whereby individual maximum demands of each load usually occur at different times.

Diversity factor. The ratio of the sum of the demands of a group of users to their coincident maximum demand during a specified period of time (e.g., summer or winter).

Early retirement (ER). An early retirement scenario occurs when existing, functional, actively used equipment is replaced with similar, higher efficiency equipment. The equipment being replaced should have at least one year of remaining useful life (RUL). In this case, a dual baseline will have to be considered, which uses the pre-existing equipment as the baseline for savings during the RUL period, and code requirement/industry standard practice baseline for estimating the balance of the EUL period for the new equipment.

End use. General categories of energy efficiency measures reflecting the type of services provided (e.g., lighting, HVAC, motors, and refrigeration). Also referred to as measure category.

End-use metering. The direct measuring of energy consumption or demand by specific end-use equipment, typically as part of load research studies or to measure the impacts of demand-side management programs.

Energy efficiency ratio (EER). A measure of efficiency in air conditioning and heat pump units within a certain capacity range. This is the ratio of the cooling capacity in Btus per hour to the total electrical input in watts, under specified test conditions (expressed in Btu/ (W-hr).

***Energy efficiency service provider (EESP).** A person or other entity that installs energy efficiency measures or performs other energy efficiency services under this section. An energy efficiency service provider may be a retail electric provider or commercial customer, provided that the commercial customer has a peak load equal to or greater than 50 kW. An energy efficiency service provider may also be a governmental entity or a non-profit organization, buy may not be an electric utility.

***Energy savings.** A quantifiable reduction in a customer's consumption of energy that is attributable to energy efficiency measures, usually expressed in kWh or MWh. (§ 25.181 (c) (18))

Engineering model. Engineering equations used to calculate energy use and savings. These models are usually based on a quantitative description of physical processes that transform delivered energy into useful work, such as heat, lighting, or motor drive. In practice, these models may be reduced to simple equations in spreadsheets that calculate energy use or savings as a function of measurable attributes of customers, facilities, or equipment (e.g., lighting use = watts x hours of use).

ERCOT weather zones. The eight weather zones used by the Electric Reliability Council of Texas to represent distinct geographic regions of Texas.

Error: The deviation of measurements from the true value of the variable being observed; also called *measurement error*.

***Estimated useful life (EUL).** The number of years until 50% of installed measures are still operable and providing savings and is used interchangeably with the term "measure life." The EUL determines the period over which the benefits of the energy efficiency measure are expected to accrue. (§ 25.181 (c) (19))

EUMMOT. The Electric Utility Marketing Managers of Texas (EUMMOT) is a voluntary organization of electric investor-owned utilities formed to address utility industry energy efficiency issues and serving as a forum to facilitate coordination among the energy efficiency program managers across the state.

EUMMOT EUL Summary Spreadsheet. This is a current list of the approved EULs for residential and commercial energy efficiency measures. The list is updated and maintained by EUMMOT and available from the Texas Energy Efficiency website under the Regulatory Filings\Deemed Savings tab. It contains the EULs, as well as a reference to the source/citation, including the relevant petition number. See: http://www.texasefficiency.com/images/documents/RegulatoryFilings/eulsummaryspreadsheetapril2013.xls.

***Evaluated Savings.** Savings estimates reported by the EM&V contractor after the energy efficiency activities and an impact evaluation have been completed. Differs from claimed savings in that the EM&V contractor has conducted some of the evaluation and/or verification activities. These values may rely on claimed savings for factors such as installation rates and the Technical Reference Manual for values such as per unit savings values and operating hours. These savings estimates may also include adjustments to claimed savings for data errors, per unit savings values, operating hours, installation rates, savings persistence rates, or other considerations. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values. (§ 25.181 (c) (20))

FEMP M&V Guidelines. U.S. Department of Energy Federal Energy Management Program's *2008 M&V Guidelines: Measurement and Verification for Federal Energy Projects*.

Fuel Switching. Using an alternative fuel (usually of lower carbon intensity) to produce required energy.

Heating Degree Days. See *degree days*.

Home Energy Rating System (HERS). An indexing system, associated with ENERGY STAR®, used in residential new construction to rate the pre- and post-construction of new homes to highlight and indicate the degree of energy efficiency embedded in the construction. The HERS Index is a scoring system established by the Residential Energy Services Network (RESNET) in which a home built to the specifications of the HERS Reference Home (based on the 2006 International Energy Conservation Code) scores a HERS Index of 100, while a net zero energy home scores a HERS Index of 0. The lower a home's HERS Index, the more energy efficient it is in comparison to the HERS Reference Home. Each 1-point decrease in the HERS Index corresponds to a 1% reduction in energy consumption compared to the HERS Reference Home.

HVAC, HVAC&R. Heating, Ventilation and Air Conditioning. Heating, Ventilation, Air Conditioning and Refrigeration.

Indirect Energy (Demand) Savings (Indirect Program Energy Savings). The use of the words "indirect savings" or "indirect program savings" refers to programs that are typically information, education, marketing, or outreach programs in which the program's actions are expected to result in energy savings achieved through the actions of the customers exposed to the program's efforts, without direct enrollment in a program that has energy-savings goals.

Inspections. Site visits to facilities treated under an energy efficiency program that document the existence, characteristics, and operation of baseline or project equipment and systems, as well as factors that affect energy use. Inspections may or may not include review of commissioning or retro-commissioning documentation.

In-Service Rate (ISR). The percentage of measures that are incentivized by an energy efficiency program that are actually installed in a defined period of time. The installation rate is calculated by dividing the number of measures installed by the number of measures incented by an energy efficiency program in a defined period of time.

Interactive Effects. For typical definition, see "Interactive HVAC Effects". However, this can also refer to the interaction of a *package* of measures *that impact the same end use*, and the resulting reduction of measure savings for an *individual* measure versus that achieved by the *package*.

Interactive HVAC (&R) Factors. The factors used to adjust basic lighting savings for interactive HVAC&R effects. Space types and factors used in the TRM are shown below. Note that “Electric Refrigerated” means air-conditioned spaces, and “Refrigerated Spaces” refers to both building floor areas and equipment spaces cooled to temperatures lower than 41 degrees Fahrenheit.

Table A-1: Deemed Interactive HVAC Effects

Space Conditioning Type	Energy Interactive HVAC Factor	Demand Interactive HVAC Factor
Air Conditioned	1.05	1.10
Med. Temp Refrigeration (33-41ºF)	1.25	1.25
Low Temp Refrigeration (-10-10ºF)	1.30	1.30
None (Uncooled/Unrefrigerated)	1.00	1.00

***International Performance Measurement and Verification Protocol (IPMVP).** A guidance document issued by the Efficiency Valuation Organization with a framework and definitions descripting the M&V approaches. (§ 25.181 (c) (33))

***Lifetime Energy (Demand) Savings.** The energy (demand) savings over the lifetime of an installed measure(s), project(s), or program(s). May include consideration of measure estimated useful life, technical degradation, and other factors. Can be gross or net savings. (§ 25.181 (c) (34))

Load Factor. A percentage indicating the difference between the amount of electricity a consumer used during a given time span and the amount that would have been used if the use had stayed at the consumer’s highest demand level during the whole time. The term also means the percentage of capacity of an energy facility, such as a power plant or gas pipeline, that is used in a given period of time. It is also the ratio of the average load to the peak load during a specified time interval.

Load Shapes. Representations such as graphs, tables, and databases that show the time-of-use pattern of customer or equipment energy use. These are typically shown over a 24-hour or whole-year (8,760 hours) period.

Main Meter: The meter that measures the energy used for the whole facility. There is at least one meter for each energy source and possibly more than one per source for large facilities. Typically, utility meters are used, but data loggers may also be used as long as they isolate the load for the facility being studied. When more than one meter per energy source exists for a facility, the main meter may be considered the accumulation of all the meters involved.

Market Penetration. A measure of the diffusion of a technology, product, or practice in a defined market, as represented by the percentage of annual sales for a product or practice, the percentage of the existing installed stock for a product or category of products, or the percentage of existing installed stock that uses a practice.

Market Saturation. A percentage indicating the proportion of a specified end-user market that contains a particular product. An example would be the percentage of all households in a given geographical area that have a certain appliance.

Market Sectors. General types of markets that a program may target or in which a service offering may be placed. Market sectors include categories such as residential, commercial, industrial, agricultural, government, and institutional.

Market Segments. A part of a market sector that can be grouped together as a result of a characteristic similar to the group. For example, within the residential sector are market segments such as renters, owners, multifamily, and single-family.

Measure. [verb] Use of an instrument to assess a physical quantity or use of a computer simulation to estimate a physical quantity.

Measure. [noun] See *energy efficiency measure*.

Measure Categories. This is also referred to as the end use, or the general category that the measure falls into. Examples include, but are not limited to, HVAC, lighting, water heating, and food service.

[TRM] Measure Overview. There is one measure overview section per TRM measure, and it encapsulates all the information needed to characterize the measure, calculate the deemed savings, document the sources used for those calculations, track changes made to the measure overview, and record any issues and recommendations for improving the approach.

Measure Persistence. The duration of an energy-consuming measure, considering business turnover, early retirement of installed equipment, technical degradation factors, and other reasons measures might be removed or discontinued.

Measurement Boundary. The boundary of the analysis for determining direct energy and/or demand savings.

Metering. The collection of energy-consumption data over time through the use of meters. These meters may collect information with respect to an end use, a circuit, a piece of equipment, or a whole building (or facility). *Short-term metering* generally refers to data collection for no more than a few weeks. *End-use metering* refers specifically to separate data collection for one or more end uses in a facility, such as lighting, air conditioning, or refrigeration. *Spot metering* is an instantaneous measurement (rather than over time) to determine an energy consumption rate.

Monitoring. The collection of relevant measurement data over time at a facility, including but not limited to energy consumption or emissions data (e.g., energy and water consumption, temperature, humidity, volume of emissions, hours of operation) for the purpose of savings analysis or to evaluate equipment or system performance.

New Construction. Residential and nonresidential buildings that have been newly built or have added major additions. Programs focusing on New Construction focus on the installation of equipment over the standard codes baseline at time of installation. Energy and demand savings are calculated in a similar method to those for Replace-on-Burnout (ROB) projects, as the savings are taken based on a codes/standard baseline.

Panel Data Model. An estimation analysis model that contains many data points over time rather than averaged, summed, or otherwise aggregated data.

Peak Demand Period. The EE Rule defines the full peak period as the hours from 1 p.m. to 7 p.m. during the months of June, July, August and September, and the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. during the months of December, January and February (excluding weekends and Federal holidays). These are also referred to as the “summer peak period’ and the “winter peak period”.

Peak Demand Reduction. Consistent with the EE Rule, this is defined as the reduction in demand during the times of the utility’s summer peak period or winter peak period. Peak demand savings will be calculated based on measure-specific hourly loads during those top hours identified in defining the peak period.

Peak Hours. This appendix outlines a process for calculating the peak hours through analytically identifying specific hours within the *Rule-defined peak demand period* that the system is most likely to realize its greatest demand. To estimate the peak hours for both the summer and winter periods, a probabilistic modeling approach developed by Frontier is used to identify the top 20 hours for each season by TRM Climate Zone.

Peak Probability Analysis (PPA). This is the name used to describe the regression-based approach used by Frontier to develop the peak demand hours used to estimate peak demand reduction and CFs for 8760 or other load shape data.

Peak Demand Probability Factors. These probability factors are outputs from the PPA models that reflect the relative probability that a TRM Climate Zone seasonal (summer/winter) peak load will occur on a given hour from a TMY dataset. Considering day of the week according to the model year used in conjunction with the TMY data, the 20 TMY hours with the highest peak demand probability factors are included in the set of 20 peak hours (summer or winter) used to estimate peak demand impacts for a given measure in a given TRM Climate Zone.

Petitions. Petitions are filed by the utilities as needed to update existing deemed savings or file new deemed savings for PUCT approval. The Deemed Savings Tracker on the Texas Energy Efficiency website provides a list of deemed savings petitions filed over the years. You can find the petitions and associated filings using the Project Number (also called a “Control Number”) on the PUCT website: http://interchange.puc.state.tx.us.

Potential Studies. Studies conducted to assess market baselines and future savings that may be expected for different technologies and customer markets over a specified time horizon.

Prescriptive Program. An energy efficiency program focused on measures that are one-for-one replacements of the existing equipment and for which fixed customer incentives can be developed based on the anticipated similar savings that will accrue from their installation.

Primary Effects. Effects that the project or program are intended to achieve. For efficiency programs, this is primarily a reduction in energy use (and/or demand) per-unit of output.

Probability-Adjusted Peak Demand. A peak demand estimate created by weighting demand estimates for each of the 20 peak (summer or winter) hours derived using a given TMY dataset for a given TRM Climate Zone and weighting those estimates by their respective *peak demand probability factors*.

Program Administrator. An entity selected by a regulatory or other government organization to contract for and administer an energy efficiency portfolio within a specific geographic region and/or market. Typical administrators are utilities selected by a public service commission or a nonprofit or state government agency, as determined by legislation.

Program Year (PY). The calendar year approved for program implementation. Note that program years can be shorter than 12 months if programs are initiated mid-year.

Project. An activity or course of action involving one or multiple energy efficiency measures at a single facility or site.

Projected Savings. Values reported by an electric utility prior to the time the energy efficiency activities are implemented are typically estimates of savings prepared for program and/or portfolio design or planning purposes. These values are based on pre-program or portfolio estimates of factors such as per-unit savings values, operating hours, installation rates, and savings persistence rates. These values may utilize results of prior evaluations and/or values in the Technical Reference Manual. Can be indicated as first year, annual demand or energy savings, and/or lifetime energy or demand savings values. Can be indicated as gross savings and/or net savings values.

Project Sponsor. See Energy Efficiency Service Provider (EESP) definition. EESPs are often referred to as the project sponsor.

Regression Analysis. Analysis of the relationship between a dependent variable (response variable) to specified independent variables (explanatory variables). The mathematical model of their relationship is the regression equation.

Remaining Useful Life (RUL). The RUL is an estimate of the number of years a piece of equipment would remain operational, in the event that it was not replaced due to program intervention. In the case of HVAC units, the RUL is a function of the technology, and age of the replaced unit. A separate table is provided for units in which the age of the equipment is unknown. The RUL estimate in years is usually much lower than the EUL.

Replace-on-Burnout (ROB). ROB defines a situation where an older, inoperable unit was replaced after failure or the equipment is older than the estimated average EUL. For this scenario, the measure baseline condition would be based on a code/standard or "standard practice", rather than the efficiency of the equipment that was previously installed.

Retrofit (RET). Energy efficiency activities undertaken in existing residential or nonresidential buildings, where existing inefficient equipment or systems are replaced by energy-efficient equipment or systems or where efficient equipment or systems are added to an existing facility (e.g., addition of thermal insulation). This can include both Early Retirement (ER) and Replace-on-Burnout (ROB).

Retrofit Isolation. The savings measurement approach defined in IPMVP Options A and B, as well as ASHRAE Guideline 14, that determines energy or demand savings through the use of meters to isolate the energy flows for the system(s) under consideration. IPMVP Option A involves "Key Parameter Measurement" and IPMVP Option B involves "All Parameter Measurement."

Seasonal Energy Efficiency Ratio (SEER). A measure of efficiency in air conditioning units and heat pump units within a certain capacity range. This is the total cooling output in Btus during its normal usage period for cooling, divided by the total electrical energy input in watt-hours during the same period, as determined using specified federal test procedures.

Seasonally-Varying Measures. Any measure whose performance, energy use, and demand varies seasonally or monthly due to changes in operation (like agricultural businesses), schools, outdoor lighting, or even residential lighting (lights on sooner and higher percentage on during the winter due to shorter and sometimes darker days).

Secondary Effects. Unintended impacts of the project or program such as rebound effect (e.g., increasing energy use as it becomes more efficient and less costly to use), activity shifting (e.g., when generation resources move to another location), and market leakage (e.g., emission changes due to changes in supply or demand of commercial markets). Secondary effects can be positive or negative.

Simple Measurement & Verification Savings Approach. A simple M&V approach falls between a deemed calculation approach and a Full M&V approach, in that only some of the deemed calculation parameters are measured, whereas for a Full M&V approach all of the algorithm parameters would be measured.

Statistically Adjusted Engineering (SAE) Models. A category of statistical analysis models that incorporate the engineering estimate of savings as a dependent variable. The regression coefficient in these models is the percentage of the engineering estimate of savings observed in changes in energy use. For example, if the coefficient on the SAE term is 0.8, this means that the customers are on average realizing 80% of the savings from their engineering estimates.

Stipulated Values. A specified and *agreed upon* value to be used in energy and/or demand savings calculations. The basis and process for developing this value should be recorded along with the values, so that when/if better information or data becomes available, a revision of the values can be considered. Usually used in the context of “measurement” versus “stipulated” values and considering the required rigor/accuracy/certainty required for a specific parameter and the resulting savings estimate.

Technical Degradation Factor. A multiplier used to account for time-and use-related change in the energy savings of a high-efficiency measure or practice relative to a standard-efficiency measure or practice due to technical operational characteristics of the measures, including operating conditions and product design.

TRM Climate Zone/Region. TMY3 weather data is used to produce normalized deemed savings estimates for weather-sensitive measures. Rather than using a multitude of weather stations, only five weather stations are used to represent the region served by the EUMMOT utilities. The five climate zone/regions and their representative cities are:

- TRM Climate Zone 1 (Panhandle Region): Amarillo International AP [Canyon - UT]
- TRM Climate Zone 2 (North Region): Dallas-Fort Worth Intl AP
- TRM Climate Zone 3 (South Region): Houston Bush Intercontinental
- TRM Climate Zone 4 (Valley Region): Corpus Christi International AP
- TRM Climate Zone 5 (West Region): El Paso International AP [UT]

TRM climate zone/region mapping is done at the county level.

Uncertainty. The range or interval of doubt surrounding a measured or calculated value within which the true value is expected to fall within some degree of confidence.

Upstream Program. A program that provides information and/or financial assistance to entities in the delivery chain of high-efficiency products at the retail, wholesale, or manufacturing level. Such a program is intended to yield lower retail prices for the products.

Utility Program Tracking Data. The data sources in which utility energy efficiency measure savings and associated project information is stored. Tracking data is used for the EM&V process. Often shortened to “program tracking data” or just “tracking data”.

Weather-Sensitive Measures. Any measure whose performance, energy use, and demand are influenced by the weather. HVAC (direct and indirect like building shell measures) and water heating measures are the most obvious example.

Whole-Building Calibrated Simulation Approach. A savings measurement approach (defined in IPMVP Option D and ASHRAE Guideline 14) that involves the use of an approved computer simulation program to develop a physical model of the building in order to determine energy and demand savings. The simulation program is used to model the energy used by the facility before and after the retrofit. The pre- or post-retrofit models are calibrated with measured energy use and demand data as well as weather data.

Whole-Building Metered Approach. A savings measurement approach (defined in the IPMVP Option C and ASHRAE Guideline 14) that determines energy and demand savings through the use of whole-facility energy (end-use) data, which may be measured by utility meters or data loggers. This approach may involve the use of monthly utility billing data or data gathered more frequently from a main meter.

APPENDIX B: PEAK DEMAND REDUCTION DOCUMENTATION

A separate excel spreadsheet attachment to the TRM (*TRM Appendix B Peak Demand Reduction Documentation.xls*) details the peak demand reduction calculation methods at the measure level.

The EM&V team researched petitions and other available program documentation to document the peak demand reduction calculations at the measure level. For some measures, the peak demand reduction calculation method was not available in petitions or documentation. While the EM&V team has been discussing these methods with various EESPs to document every measure, there are still some areas where the information has not yet been identified. The EM&V team will continue to update the documentation of peak demand reductions at the measure-level as updates are made.