MONITORING AND DATA COLLECTION STANDARD FOR DISTRIBUTED ENERGY RESOURCE (DER) SYSTEMS

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1 Introduction

This document describes the measurements necessary to characterize the performance of several types of distributed energy resource (DER) systems that report data to the NYSERDA DER Integrated Data System (IDS) website. As DER configuration will vary with each installation, the goal of this standard is to provide a common framework for measuring DER performance. The standard provides the metering accuracy needed for compliance, and displays examples of measurement and sensor locations for several common DER configurations, and is not intended to be exhaustive.

2 Required Measurements per DER Type

Data for four major DER types is currently presented on the NYSERDA DIS website; Solar, Fuel Cells, Anaerobic Digester Gas (ADG), and Combined Heat and Power (CHP). Each type of DER has a key performance index (KPI) that is **required** to be measured in compliance with the guidance of this document. Additional measurement beyond the KPI may be requested by NYSERDA as necessary to characterize a specific DER's performance.

Table 1. Required Measurement Per DER Type

DER Type	Key Performance Index(s)	Minimum Measurements Required	Units
Solar PV	Electricity Generation	Electricity Production	kWh
Fuel Cells	Electricity Generation Electrical Efficiency	Electricity Production Fuel Input	kWh CF
ADG	Electricity Generation Electrical Efficiency Exhaust Quality	Electricity Production Fuel Input Hydrogen Sulfide Level	kWh CF PPM
CHP	Electricity Generation Electrical Efficiency CHP Efficiency	Electricity Production Useful Heat Recovery Fuel Input	kWh MBtu CF
Energy Storage	TBD	TBD	TBD

Requirements and KPI for monitoring and characterizing energy storage DERs are under development and are not covered in this standard.

2.1 Electricity Generation (ALL DERs)

Electricity generation is the **NET** electrical output from the DER. Net output subtracts the parasitic or ancillary loads needed to operate the DER. The measurement should represent the DERs contribution to offset electricity at the utility meter for the host facility or the utility grid. Net electrical output may be measured directly, by placing CTs downstream of both the generation source and parasitic/ancillary loads. Alternatively, net electrical output may be measured "virtually" by computing the simultaneous difference of two or more electric meters, with one meter measuring the gross output of the DER and the other meters measuring the parasitic/ancillary loads directly.

Parasitic and ancillary electric loads include, but are not limited to:

- Circulating pumps on the DER side of Building Load HX
- DER Heat Rejection including Dump Radiators, Dry Coolers, and Cooling Towers
- Natural Gas Compressors
- Gas Conditioning Equipment
- Inverter Cooling/Ventilation

Equipment that are on the building or load side of isolation HXs are typically **not** considered parasitic loads. Inverters are considered parasitic loads, and electricity generation measurements must be made on the output side of the inverter.

2.1.1 Electricity Generation Typical Sub-Metering Locations

The physical configuration of the electrical distribution system and electrical disconnect locations will dictate the optimal metering locations for an individual project. The schematics below display common metering configurations.

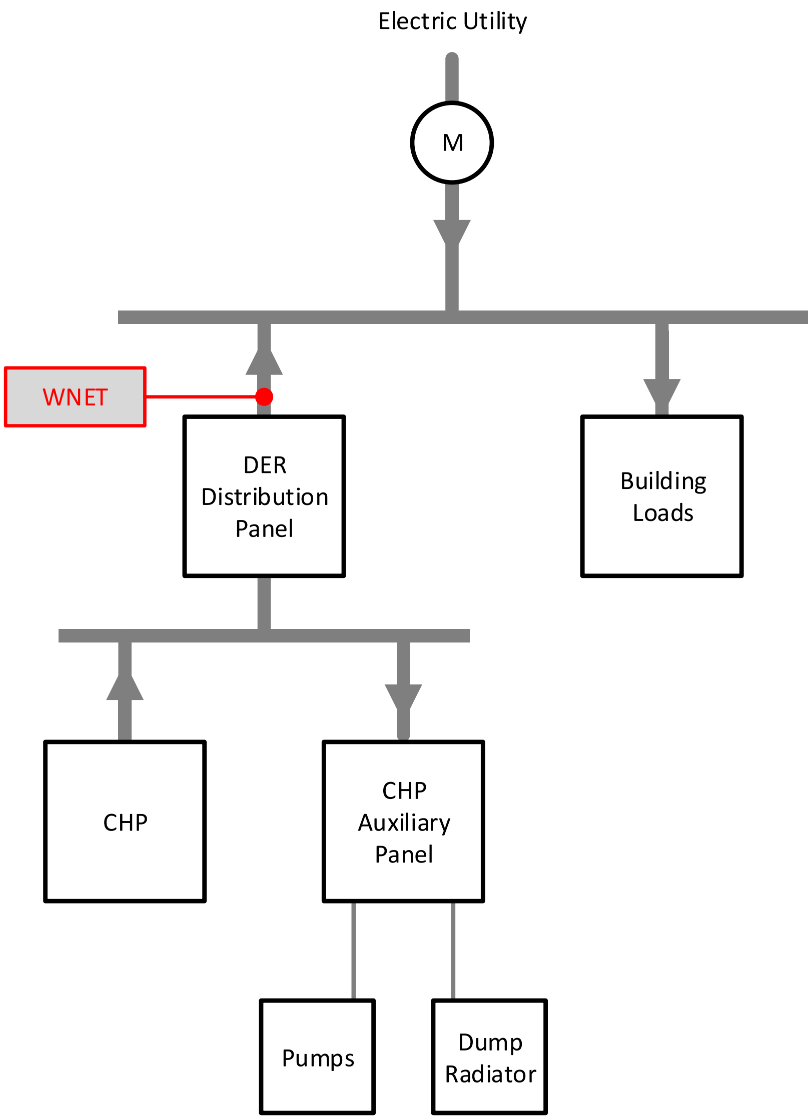

Figure 1. Direct Measurement of Net Generation (WNET)

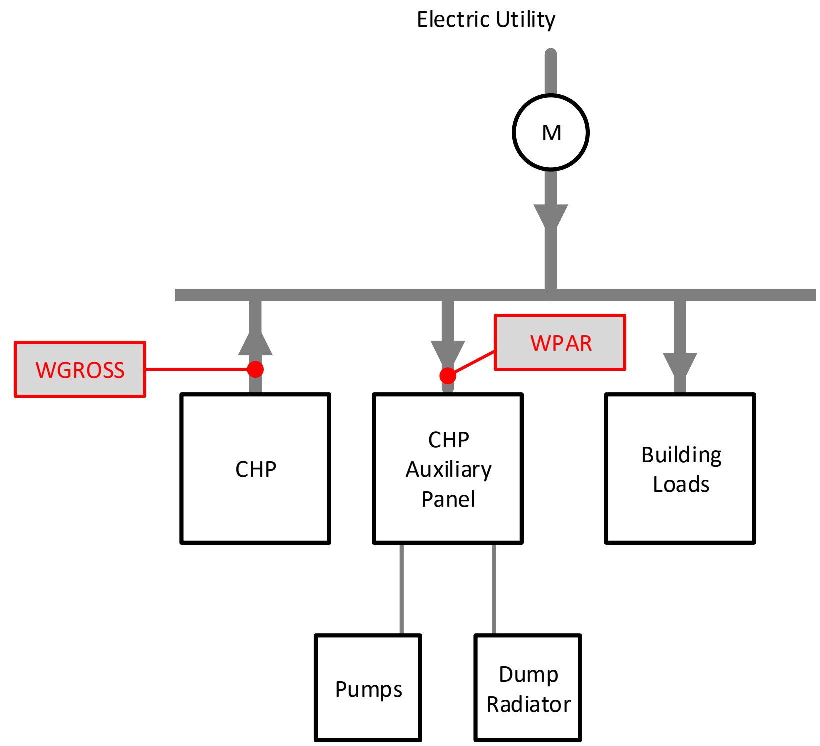

Figure 2. Indirect (Virtual) Measurement of Net Generation (WNET) = Gross (WGROSS) – Parasitic (WPAR) – typical of Small Systems

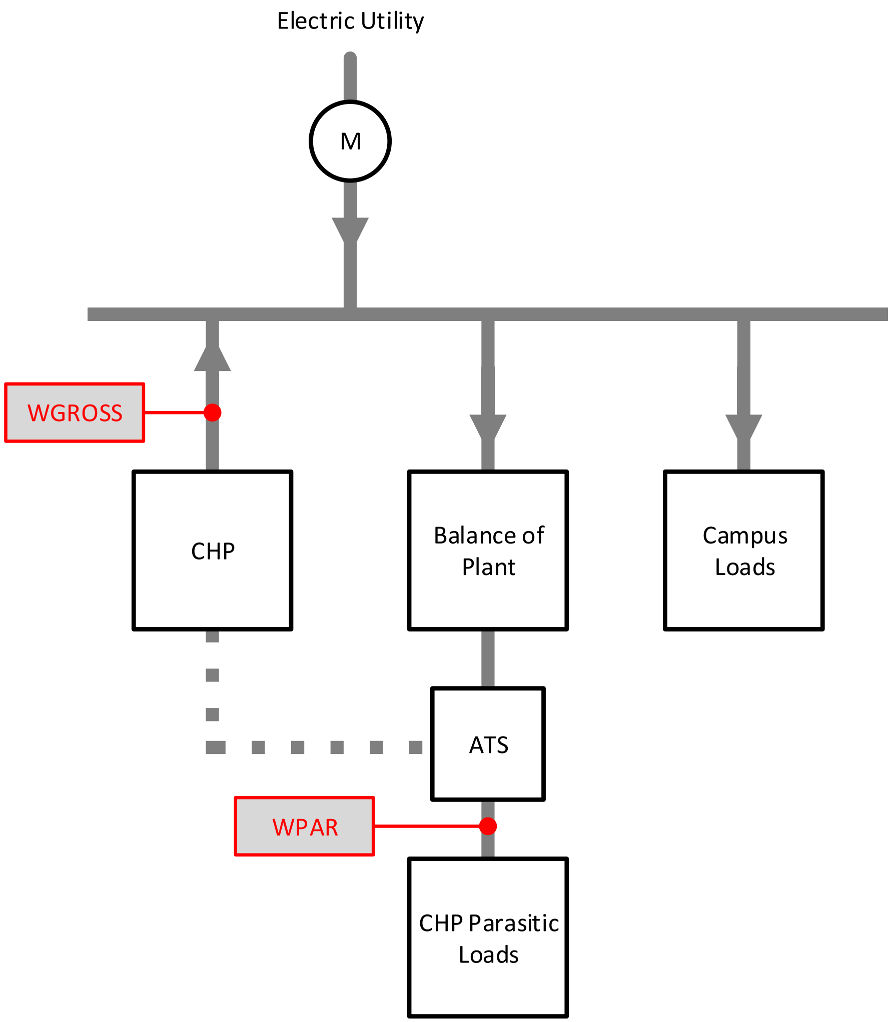

Figure 3. Indirect (Virtual) Measurement of Net Generation (WNET) = Gross (WGROSS) – Parasitic (WPAR) – typical of Large Systems

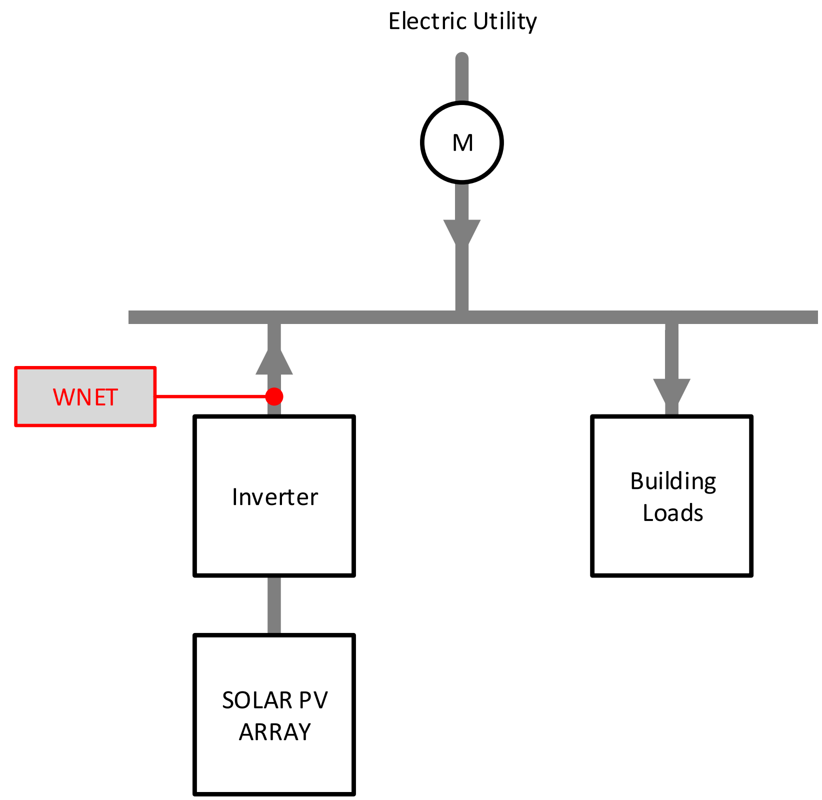

Figure 4. Net Electrical Generation (WNET) Measurement Point with DER Inverter

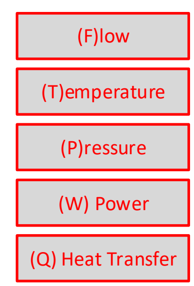

Figure 5. Key to Typical Data Point Label Used

2.1.2 Electricity Generation Sub-Metering Type and Accuracy

Metering used for DER electrical generation measurement shall use a revenue grade power meter for measuring either the net or gross output of the DER. Parasitic loads, which are typically less than 10% DER nameplate power may be measured using a non-revenue grade power transducer meeting the accuracy requirement displayed in Table 2.

Table 2. Electric Sub-Meter Requirements

Measurement	Rating Required	Accuracy
Net Power	ANSI C12.20 Class 5	± 0.5%
Gross Power	ANSI C12.20 Class 5	± 0.5%
Parasitic Loads	ANSI C12.1	± 1%

Data from engine controllers and protective relays do not satisfy the above requirements, and will not be considered acceptable metering methods by default. To utilize such measurement sources for performance data submission requires prior approval by NYSERDA and independent field verification of such equipment. If the electrical system voltage or other installation constraints prevent independent verification, a qualified power meter must be installed.

The output from the electrical sub-meters used should be a MODBUS (or comparable higher level protocol) extended data stream that has both sampled kW and accumulated kWh, or a high-density pulse output of 0.100 kWh/pulse or better. The resolution of the meter shall be comparable to the DER sizing, (e.g. a meter with a resolution of ±1 kWh is suitable for a 1 MW turbine, but not for a 100-kW reciprocating engine generator).

2.2 Fuel Input (Fuel Cell, ADG, and CHP DERs)

For fuel cell, ADG, and CHP DERs that operate on either natural gas or biogas, measurement of the fuel input to the system is required. Systems that have a dedicated utility gas service may utilize a utility supplied pulse output as the source of data. Systems that are on branch piping where a combination of DER and non-DER gas loads are connected to the main billing meter must install a dedicated gas sub-meter. ADG systems must meter both the biogas and any natural gas input to the system separately. Facilities that add on additional DER systems to an existing DER gas service **must supply dedicated gas sub-meters for the new DER systems.**

2.2.1 Fuel Input Typical Sub-Metering Locations

The physical configuration of the natural gas distribution system will dictate the optimal metering locations for an individual project. The following schematics display common metering configurations.

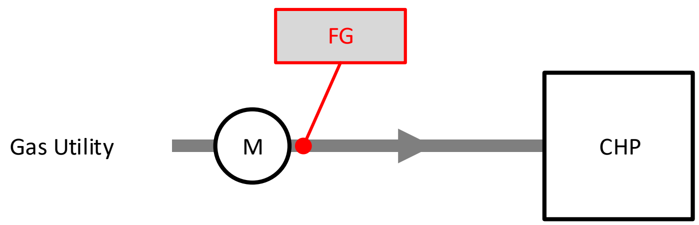

Figure 6. Direct Measurement of Gas Consumption (FG) Using Utility Meter

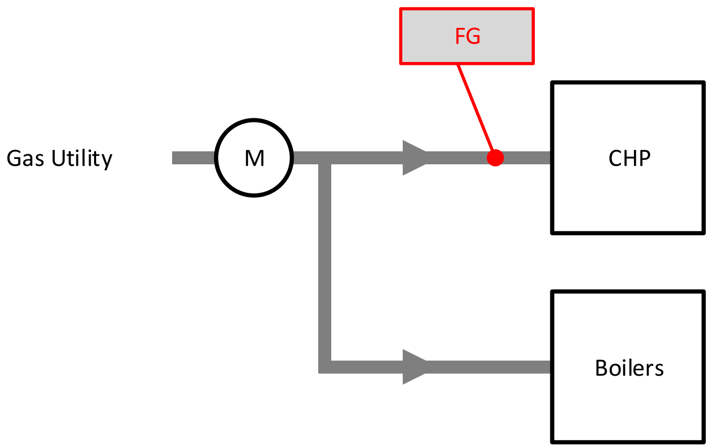

Figure 7. DER Sub-meter (FG) Required for Branch Piping Configuration

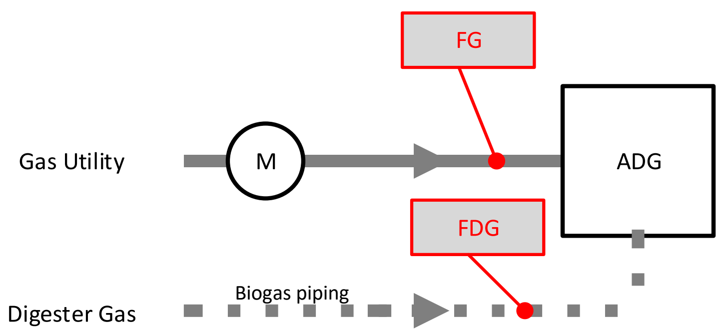

Figure 8. Measuring Natural Gas (FG) and Biogas (Digester Gas) (FDG) Separately on an ADG System

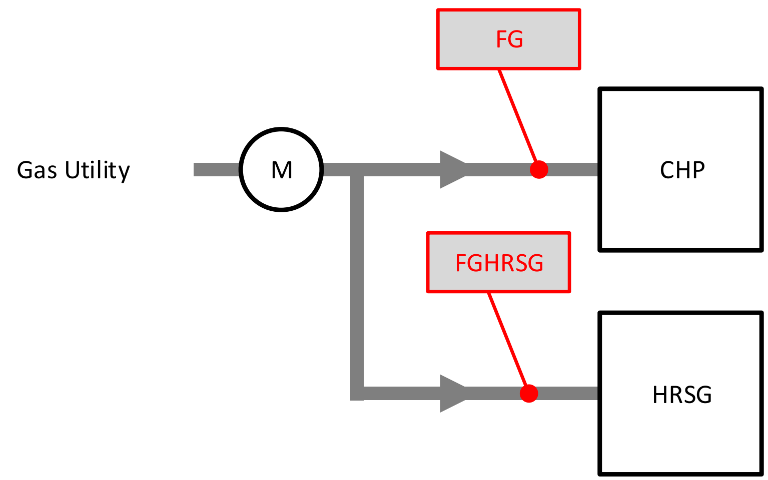

Figure 9. DER Sub-meter (FG) and HRSG Sub-meter (FGHRSG) Required for Separate Thermal Uses

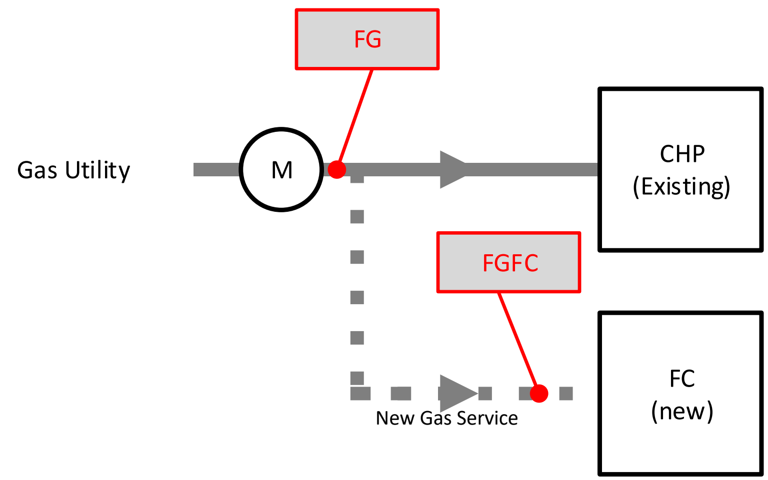

Figure 10. Adding Sub-Meter for New Fuel Cell Installation (FGFC) along existing CHP System Metered with Utility Meter (FG)

2.2.2 Fuel Input Sub-Metering Type and Accuracy

Metering used for DER fuel input shall use a gas meter that meets the stated accuracy in Table 3 and is rated for the duty and type of gas being measured. For natural gas measurements, the preferred sub-meter type is a rotary positive-displacement meter with a high-density pulse output of 10 CF/pulse. Larger pulse output constants can be used; however, this impacts the precision of the reading when examining operation of small DER units (<100 kW) on shorter time frames (such as hourly data). All natural gas metering equipment used should be pressure and temperature compensated to report data in standard cubic feet (SCF). This compensation is required if gas is delivered at elevated pressures or if the gas meter is in unconditioned space where ambient temperature can substantially influence the reading.

If utility supplied pulse outputs are used, it is important to note the pulse density compared to the DER system size. Utility supplied pulses are often either 100 CF/pulse or 1,000 CF/pulse, which again can cause resolution issues for interval data when applied on DERs with lower gas consumption rates and output capacities.

ADG systems typically use a hot-wire mass flowmeter for the biogas measurement. These types of meters utilize no moving parts, and are better suited for wet and/or corrosive environments occurring with digester gas production.

Table 3. Gas Meter Requirements

Measurement	Rating Required	Accuracy
Natural Gas Consumption	None	± 1%, P&T compensated if location requires
Digester Gas Consumption	None	± 1%, Mass Flow Meter

2.3 Heat Recovery (CHP DERs)

The CHP DERs require heat recovery measurements to be reported. Heat recovered from a CHP unit is classified as “useful” (heat provided to the host facility for beneficial use that displaces heat from other sources), or “rejected” (heat that is actively rejected to atmosphere, and does not impact the host facility). The useful heat recovery measurement is applied in calculating the key performance index CHP efficiency, and is a required measurement.

Useful heat recovery loads include, but are not limited to:

- Domestic Hot Water (DHW) heating
- Space Heating
- Make-up Air Heating
- Pool Heating
- Snow Melt
- Thermal Energy Supplied to Absorption Chillers
- Steam Production

2.3.1 Hot Water Heat Recovery Measurements

Useful heat recovered in the form of hot water or hot glycol is measured using two temperature measurements and a flow-meter. The two temperature measurements must be in the same mass flow for a meaningful heat transfer measurement to be recorded. These measurements are typically performed by a packaged BTU meter. Figure 11 and Figure 12 shows examples of the proper locations of flow and temperature measurements to record heat transfer.

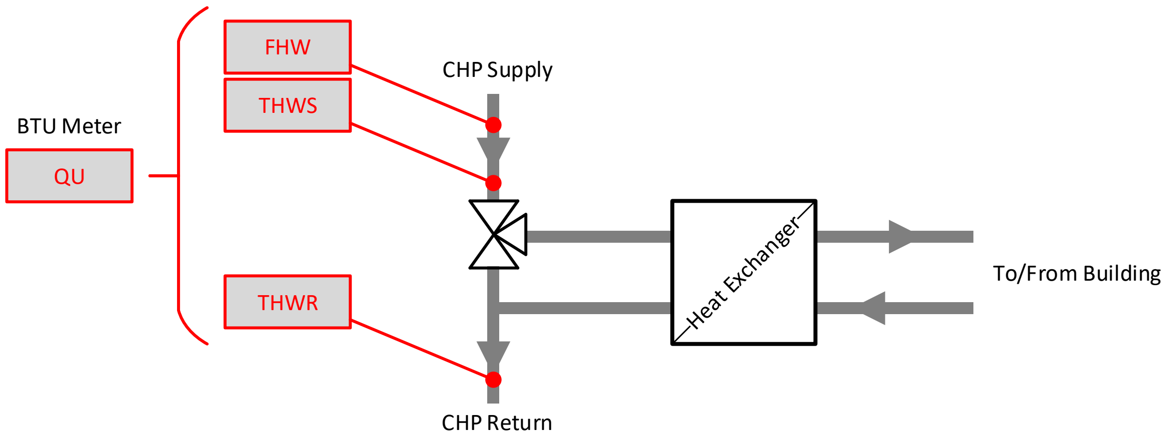

Figure 11. Measuring Useful Heat Transfer on CHP Header Piping

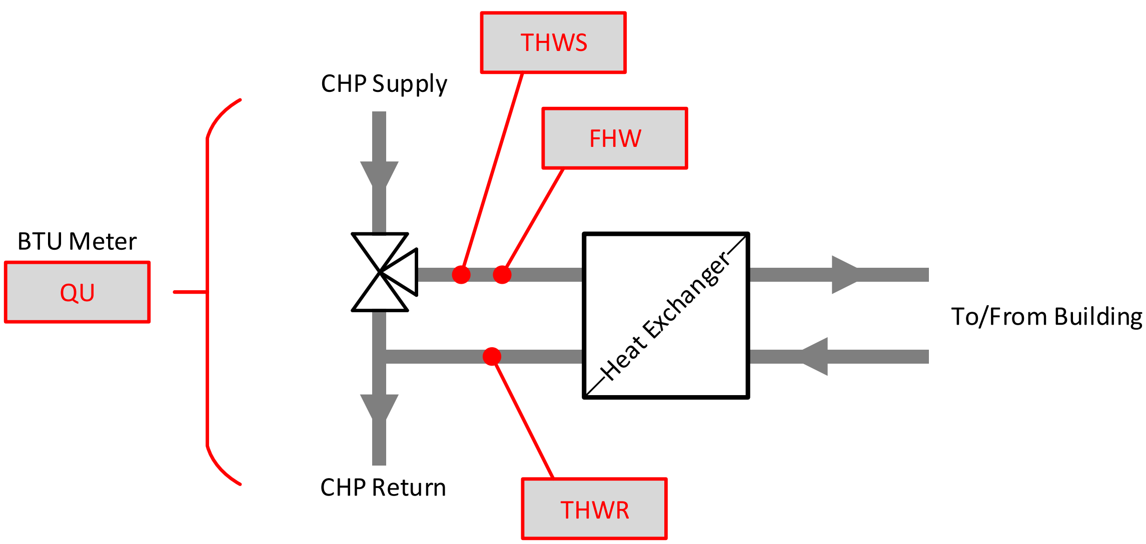

Figure 12. Measuring Useful Heat Transfer on CHP HX Branch Piping

Figure 13 displays an incorrect method of measuring heat transfer. The heat transfer flow and temperature sensors are not located in the same piping. The operation of the three-way valve results in a different flow in the branch piping where the temperature measurements are obtained compared to the measured flow in the header piping. Heat transfer cannot be measured using the configuration in Figure 13.

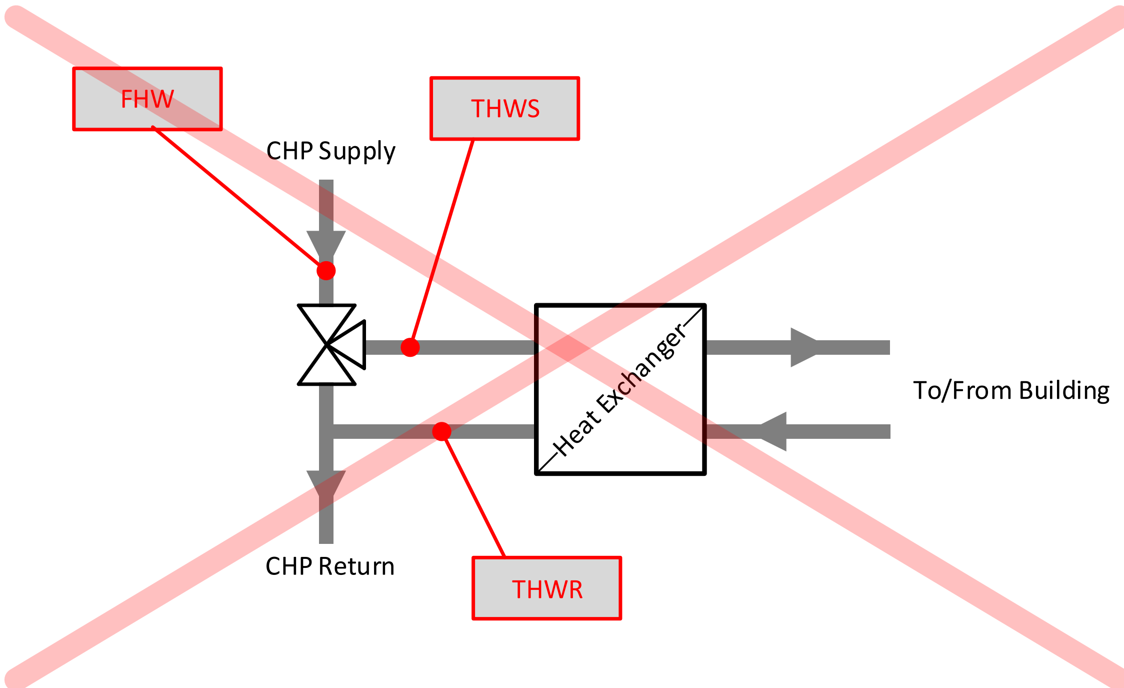

Figure 13. Incorrect Measurement of Heat Transfer – Temperatures and Flows Not in Same Piping – DO NOT USE

It is preferable to measure useful heat transfer on the CHP side of all HXs, however due to space constraints and the lack of straight pipe runs used to locate flowmeters, measurement on the building side of the HX can also be used, as displayed in Figure 14.

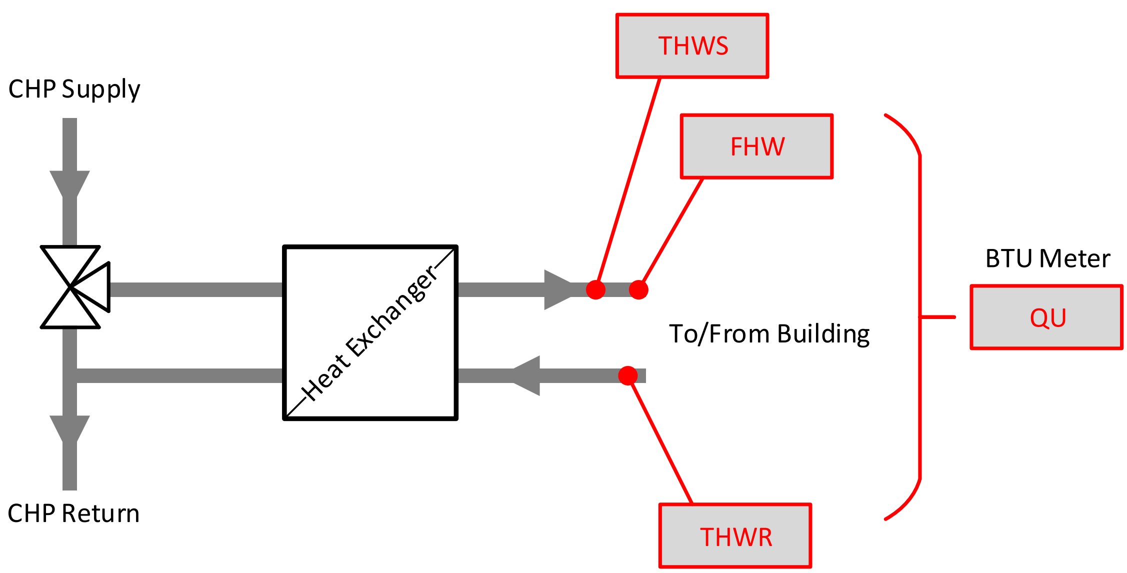

Figure 14. Measurement of Heat Transfer on Building Side of HX

Installing the heat recovery flows and temperature sensors on the header piping allows for multiple temperature sensors to be installed along with a single flow meter to collect several heat transfer measurements without a dedicated BTU meter at each location. Figure 15 displays how installing a BTU meter on the header piping at the DHW HX can be used to also calculate both the space heating heat transfer (QSH) and total useful heat transfer (QU) by adding a single additional temperature sensor THWR2. Sensors FHW and TWHR1 are implied at the measurements shown in dashes based on the upstream measurements.

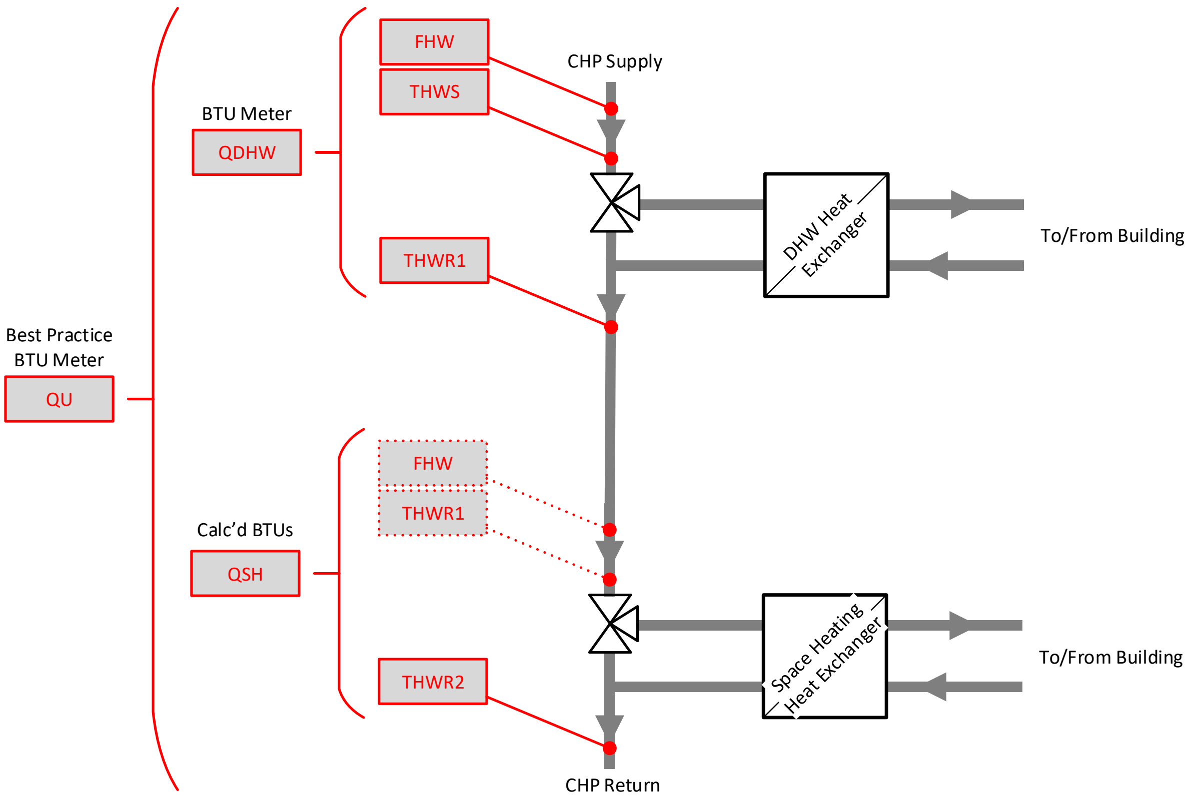

Figure 15. Measurement of Heat Transfer Using One Flowmeter and Multiple Temperatures

The following equations provide the calculation of heat transfer measurements for this example:

QDHW = k × FHW × (THWS – THWR1)

QSH = k × FHW × (THWR1 – THWR2)

QU = k × FHW × (THWS – THWR2)

The constant **k** in the equations above is the thermal constant for the heat transfer fluid, which is typically 480-500 $\frac{BTU/h}{gal\cdot°F}$, depending on the fluid type (pure water or water/glycol mixture).

Best practice dictates in the example above, the BTU meter sensors be located at the FHW, THWS, and THWR2 locations. This captures the entirety of the useful heat with a BTU meter. Adding an additional sensor at THWR1 will then allow for the separate heat recovery streams to be broken out without impacting the accuracy of the total useful heat transfer measurement.

2.3.2 Hot Water Heat Recovery Sub-Metering Type and Accuracy

Metering used for DER hot water heat recovery typically uses a BTU meter that meets the stated accuracy in Table 4 and is rated for the duty and type of fluid being measured. The BTU meter shall provide all associated temperature and flow measurements, along with the computed instantaneous and integrated BTU values provided by the meter. This typically requires a meter with a MODBUS or other higher-level protocol for an output. BTU meters that provide a pulse output only are discouraged.

Alternatively, if the data collection system can provide data at a rapid interval (e.g. 1-minute data), then the raw temperature and flow data can be utilized to compute heat transfer values off-line.

Table 4. Hot Water Heat Transfer Metering Requirements

Measurement	Rating Required	Accuracy
Hot Water/Glycol Temperature	None	± 1% or ±0.5°F
Hot Water/Glycol Flow	None - Insertion meter preferred for serviceability	± 1% sized for 120% of the nominal flowrate expected
Heat Transfer by BTU Meter	None	± 3% total based on temperature and flow accuracies

2.3.3 Steam Measurements

Heat recovery steam generator (HRSG) systems extract exhaust heat to boil feedwater to produce steam. To measure the heat recovery achieved, measurements are required on both the entering feedwater side and leaving steam side of the HRSG. On the steam side, measurement of flow, pressure, and temperature of the steam are required to establish the final enthalpy achieved. These measurements can come from a single sensor that provides all three data points, or from separate sensors, but all three measurements are required. The location of the steam meter can either be at the HRSG output (gross steam), or downstream of any ancillary steam takeoffs, such as deaerators (net steam). The location of the steam meter impacts the reference point measurements on the feedwater system, as described below.

On the feedwater side of the system the required measurement is the temperature of the water entering the system. Pressure has a negligible impact on liquid water enthalpy and can safely be ignored. The location for the HRSG feedwater temperature measurement depends on the energy source for deaerator input and the location of the HRSG steam meter. If the steam meter measures gross output from the HRSG, then the feedwater enthalpy is measured at the temperature leaving the deaerator (Figure 16). In this case, HRSG steam provides the temperature lift through the deaerator, and no credit is assigned to the HRSG for raising the feedwater from condensate to the temperature leaving the deaerator. If the steam meter measures net output (or deaerator steam is measured directly and subtracted from gross steam output), then the reference for the system becomes the enthalpy at the bulk condensate temperature returned from the building or campus (Figure 17). In this configuration, the energy used for deaerator operation has already been accounted for by the net steam measurement.

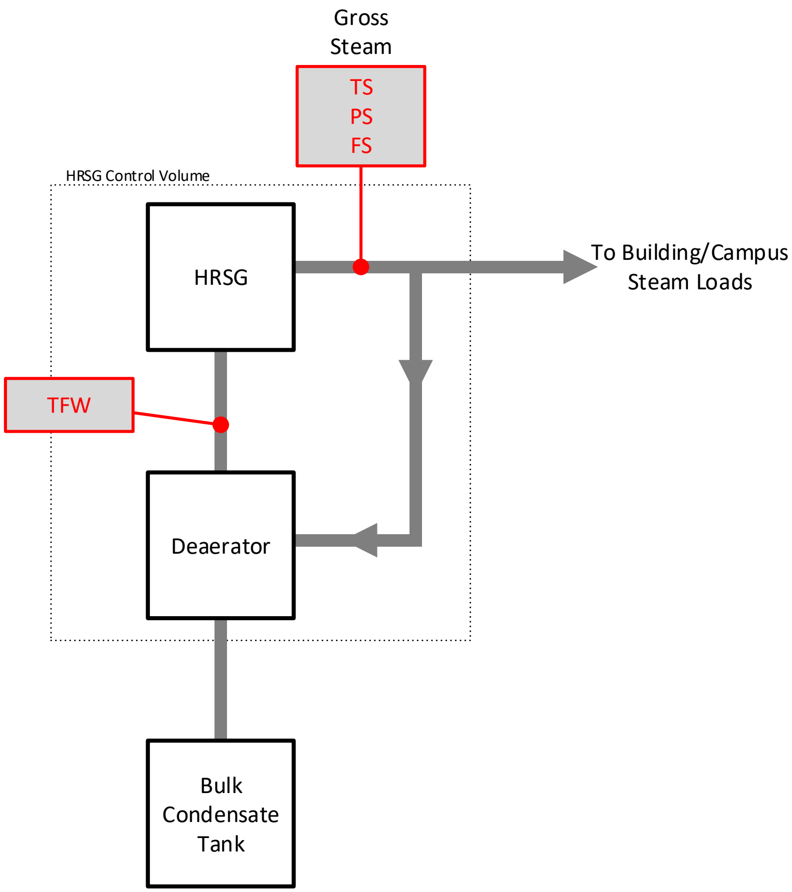

Figure 16. HRSG Measurements w/ Gross Steam Meter

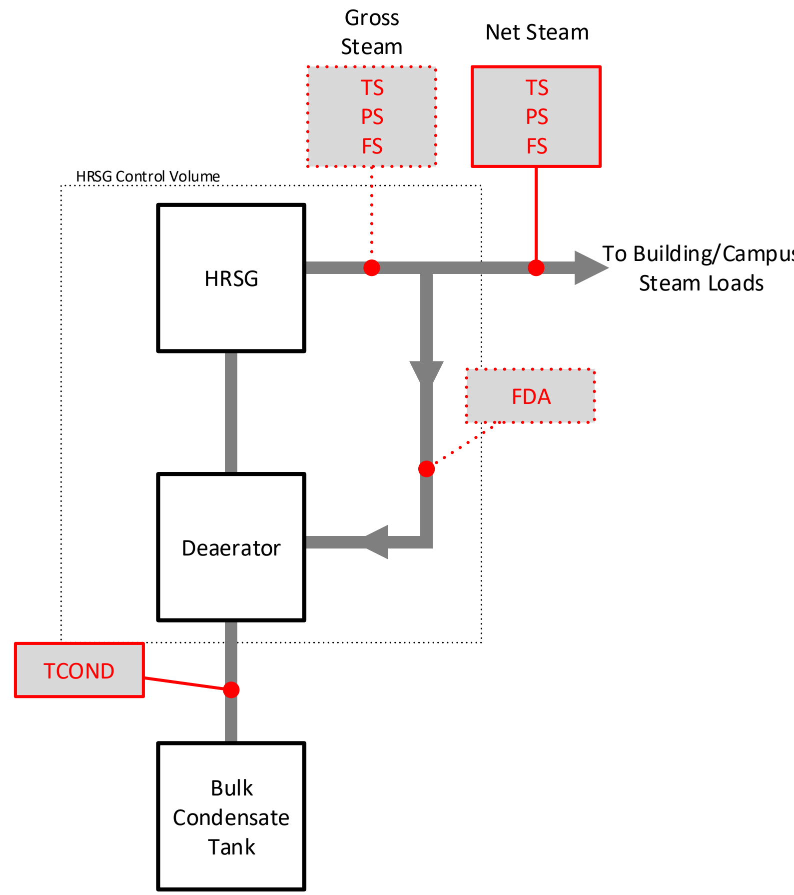

Figure 17. HRSG Measurements w/ Net Steam Meter (or Gross – DA)

If the HRSG is part of a boiler house that uses stationary boilers in conjunction with HRSG operation, and the deaerator is fed from a mixture of boiler and HRSG provided steam, then the HRSG steam flow is measured as gross steam (Figure 18).

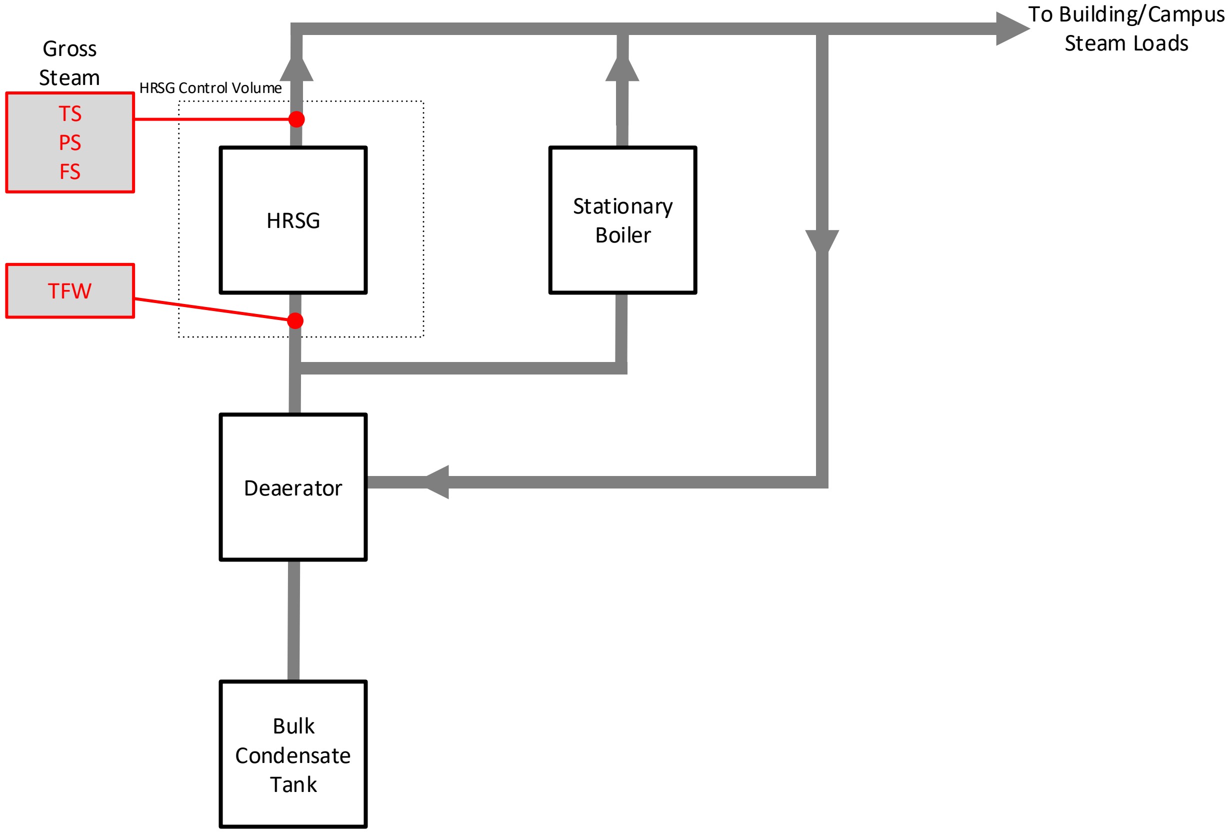

Figure 18. HRSG Measurements in Boiler Plant Configuration

For all configurations, only the feedwater and steam conditions, and steam flow data are necessary to be reported. Computation of the enthalpy for both entering and leaving locations can be performed offline using steam tables.

2.3.4 Steam Sub-Metering Type and Accuracy

Metering used for DER steam heat recovery will likely use a series of three separate sensors. Only a few steam meters on the market can provide all three flow, temperature and pressure measurements in a single sensor. The metering shall meet the stated accuracy in Table 5 and is rated for the duty and pressure of steam being measured.

Table 5. Steam Heat Transfer Metering Requirements

Measurement	Rating Required	Accuracy
Steam Flow	None	± 1% sized for 120% of the nominal flowrate expected
Steam Temperature	None	± 1% or ±0.5°F
Steam Pressure	None	± 1% full scale
Feedwater/Condensate Temperature	None	± 1% or ±0.5°F

2.4 ADG Specific Measurements

ADG DERs have additional measurements necessary to meet program reporting requirements, as shown in Table 6. The flare gas measurement is collected using mass flow sensors similar to the biogas flow to the engine, as described in Section 2.2.2. The exhaust gas hydrogen sulfide (H2S) readings required to be automatic readings sampled at least once per hour, and not random grab samples. Additional readings, such as biogas methane content, may be requested by the NYSERDA ADG Technical Consultant.

Table 6. Additional ADG Specific Metering Requirements

Measurement	Rating Required	Accuracy
Flare Gas Flow	None	± 1%, Mass Flow Meter
H2S Entering Scrubber	None	± 5%
H2S Leaving Scrubber	None	± 5%

2.5 CHP Specific Measurements

CHP DERs often have other components that NYSERDA may request data on to better understand system operation, and/or assist in downstream CHP re-commissioning. Two typical components that often require measurement are heat rejection, and absorption chillers.

2.5.1 Heat Rejection

Heat rejection systems transfer unused heat from the CHP system to the atmosphere. These typically take the form of either dry coolers (also known as dump radiators), or a heat exchanger that is coupled to the building's cooling tower system. In both cases, the heat transfer to the heat rejection system is measured like other hot water heat recovery loads covered in Section 2.3.1. Figure 19 displays an example of measuring a useful heat recovery load (DHW) in conjunction with a dump radiator to measure heat rejection, while using the single flowmeter and multiple temperature sensor technique. Sensor and accuracy requirements are like those used for hot water loads previously described.

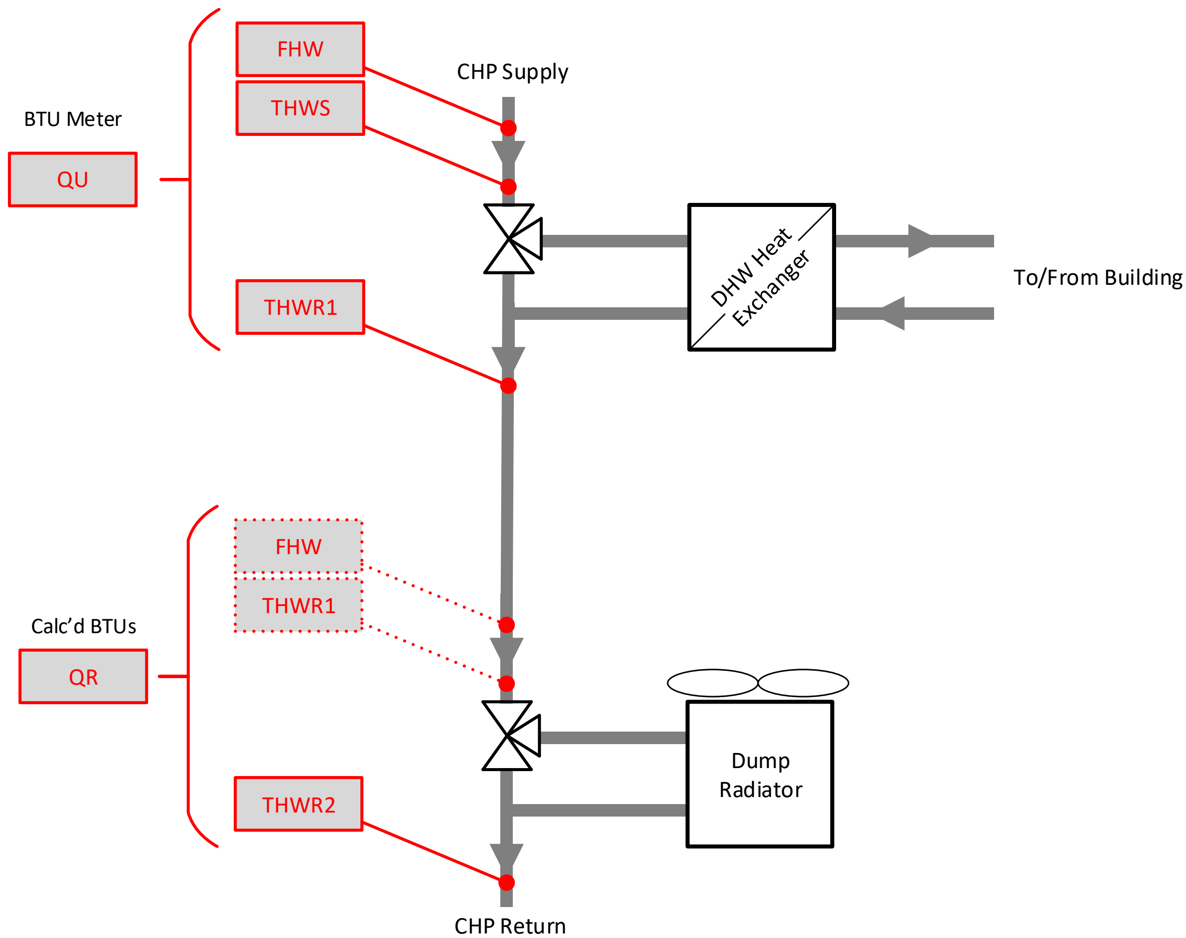

Figure 19. Heat Rejection Measurement in Combination with Useful Heat Measurement

The following equations provide the calculation of heat transfer measurements for this example:

$$QU = k \times FHW \times (THWS - THWR1)$$

$$QR = k \times FHW \times (THWR1 - THWR2)$$

2.5.2 Absorption Chillers

Absorption chiller use thermal energy provided from a CHP system to produce chilled water for use by the host facility. CHP systems that utilize absorption chillers must meter in the thermal input to the chiller, as well as the resulting chilled water output. Heat rejection from absorption chillers does not require metering. Figure 20 displays the typical required metering configuration for an absorption chiller. The useful heat recovery measurement on the hot water side of the chiller may or may not be part of a larger number of useful heat recovery loads measured. On the chilled water side, chilled water load produced shall be measured like a hot water load, using a BTU meter with a combination of flow and temperature measurements.

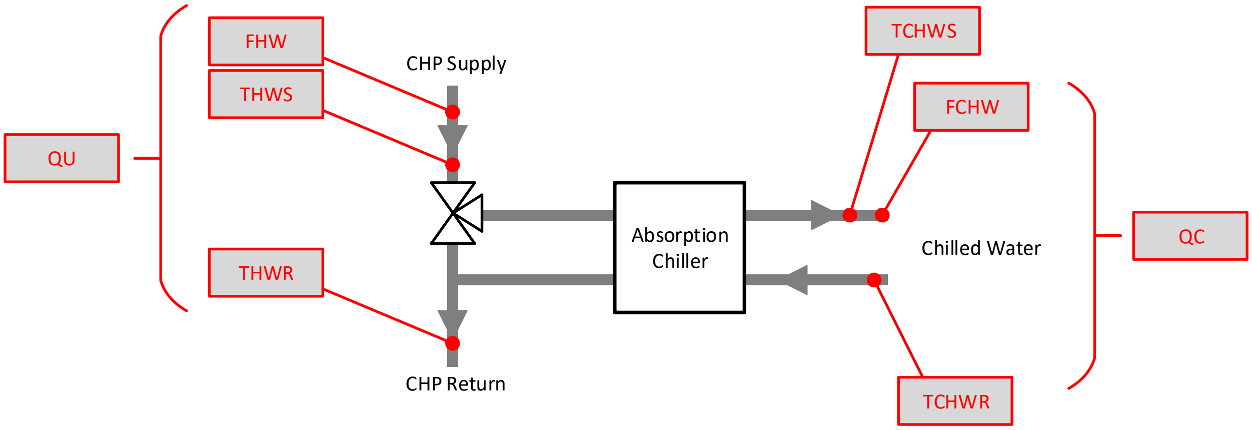

Figure 20. Absorption Chiller Measurements

Heat input to absorption chillers is included in the overall useful heat measurement for the system.

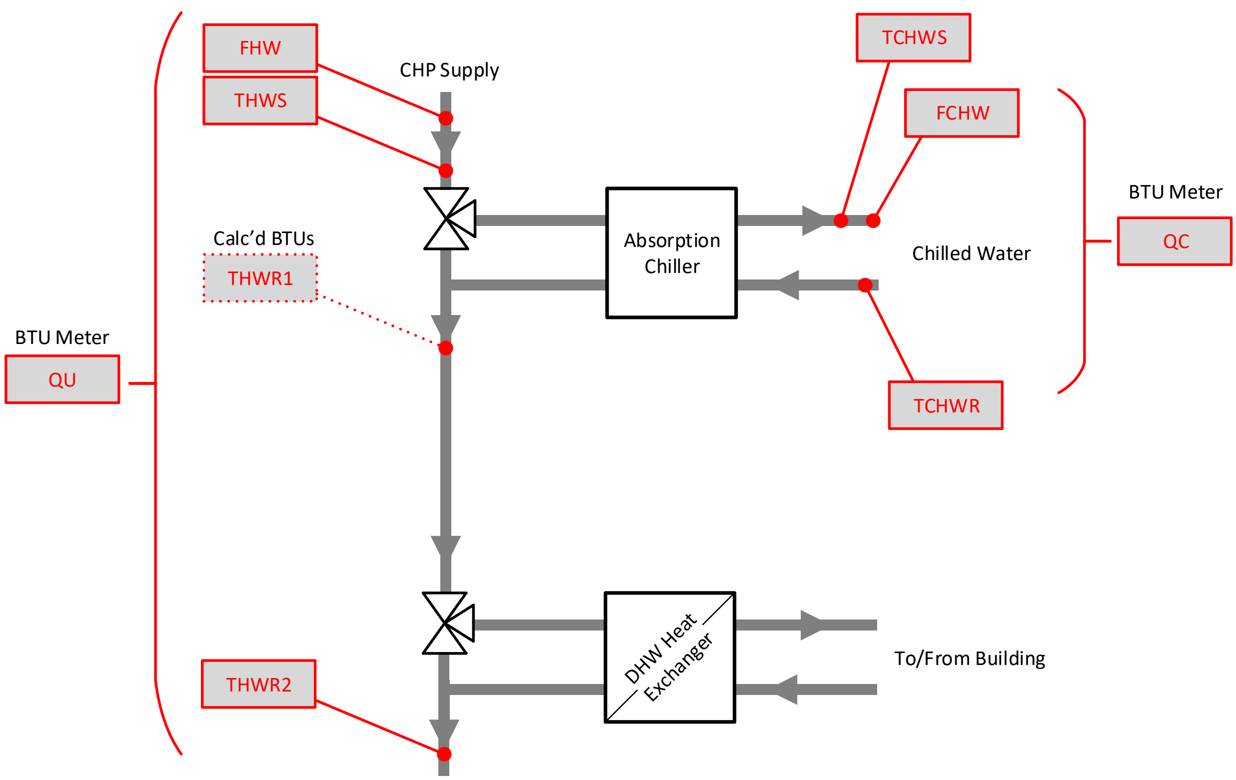

Figure 21. Absorption Chiller and DHW Measurement as Useful Heat – THWR1 included to break out heat transfer by end use

2.6 Measurement on Host Facility

All facilities with DERs installed should provide a measurement of the utility electrical import consumed by the facility. This can be provided by a dedicated power transducer, or via a measurement by the protective relay, however, if export to the utility is allowed, then a bi-directional power transducer is required. A pulse output from the utility billing meter is acceptable measurement.

Table 7. Facility Electric Sub-Meter Requirements

Measurement	Rating Required	Accuracy
Utility Import	None, ANSI C12.1 preferred	± 1%

3 Documenting Measurement Details (M&V Plan)

Documentation detailing the location and type of sensors used to measure the performance of a DER is required to be submitted to NYSERDA and to Frontier Energy in the form of a Monitoring and Verification Plan (M&V Plan), for inclusion on the IDS website. At a minimum the M&V Plan should include:

- A list of the measurements collected with the corresponding sensor type, engineering units, and data type of the readings provided
- A set of MEP (mechanical, electrical, plumbing) drawings showing the location of each sensor installed. The locations and annotations on the drawings should allow for post-installation verification of the installed sensors.
- Cut sheets for all sensors used
- A description of how the sensors are sampled and processed into interval data that conforms with the *NYSERDA Integrated Data System Data Submission Specification 2017* for transmission to Frontier Energy.
- A description of any calculations or post-processing performed on the data prior to transmission

4 Data Collection Platform

Hardware to collect and transmit data from the installed sensors to Frontier Energy is not explicitly specified. The data collection platform can be either based on a purpose-built data logger system, or utilize the DER plant control system (PCS) (typically only available on larger DER installations). Either solution must be able to provide the following functionality:

- Average or sample readings depending on sensor output type into interval data on a 1, 5, or 15-minute basis
- Write the recorded values to a file of a fixed format on a regular, automated basis (e.g. a CSV file written once per day without human intervention)
- Transfer the data file using an acceptable protocol to Frontier Energy on a regular, automated basis (e.g. once per day without human interaction)

- Have sufficient on-board storage that interval data can be stored locally in the device for up to 30-days without overwriting data (in the event of a communication disruption)
- Can communicate with Frontier Energy's servers located on the Internet without undue restriction

5 Data Types

Depending on the capabilities of the data collection platform, the data file may contain several different types of data. All three types of data are acceptable; however, the application of each data type should be described in the M&V plan narrative.

Table 8. Various Data Types Reported

Data Type	Descriptions
Averaged Data	Averaged data are the highest quality data, sampled at a regular high frequency interval (e.g. once per second), and true averages (for analog measurements) or sums (for discrete/status/runtime measurements) are recorded over the duration of the data record (e.g. average of 900 samples recorded per 15-minute data interval).
Sampled Data	Data records that are sampled only at the interval end (e.g. instantaneous reading recorded at the end of a 15-minute data interval) are of lower quality. Data collection platforms that can only sample readings will be required to submit files with a higher rate data interval (e.g. 1-minute data intervals instead of 15-minute data intervals). Sampled data at higher frequencies can be turned into meaningful hourly values during post processing, for use on the IDS.
Accumulated Data	Data records that represent either the all-time or long-term totalization of an energy flow. The reading continually counts upwards, like an odometer. This data is typically available only on "smart" power transducers or BTU meters that employ onboard calculations and utilize a higher-level protocol (e.g. MODBUS). Accumulated data provides a level of redundancy for periods where sensor or data collection platform communication is disrupted. For example, accumulated data from a smart power transducer allows for the total amount of electricity generation to be calculated from two readings several months apart, even if the data collection platform was unable to report interval data during that period.