# PUBLIC SERVICE COMMISSION OF UTAH

## Docket No. 13-035-184

Exhibit SC___DRM-2

NEM Avoided Cost Methodology

# NEM Avoided Cost Methodology

The net energy metering ("NEM") avoided cost methodology used in this study has been adapted from E3's avoided cost methodology accepted and used by the California Public Utility Commission ("CPUC") since 2004.[1]

The methodology adopted in this study consists of the following 4 components from E3's avoided cost methodology:

- Avoided Cost of Energy – the hourly marginal value of energy, adjusted for losses, that would need to be generated to meet demand if NEM installations did not exist
- Generation Capacity – the additional payments above energy and ancillary service market revenues that a generation owner would require to build new generation capacity to meet system peak loads
- Ancillary Services – the marginal cost of providing system operations and reserves for electricity grid reliability
- T&D Capacity – the costs of expanding transmission and distribution capacity to meet customer peak loads

While E3's methodology also includes the avoided cost components of $CO_2$ Emissions and Avoided Renewable Portfolio Standards, the market and policy conditions in Utah make it difficult to calculate a realistic market value for these components. That being said, these avoided cost components are real and have value in other jurisdictions, such as California.

To calculate the value of avoided costs for each individual hour of NEM PV generation, the following shaping and allocation methods in Table A1 are applied to annual forecast values:

*Table A1. Avoided Cost Components and Hourly Shaping*

| COMPONENT | BASIS OF AVOIDED COST | BASIS OF HOURLY SHAPE |
|---|---|---|
| AVOIDED COST OF ENERGY | **HISTORICAL MONTHLY HEAT RATES FOR RMP'S THERMAL FLEET AND FORWARD FUEL PRICES** | **GEOGRAPHIC SPECIFIC POWER OUTPUT FROM NREL'S PV WATTS MODEL FOR RMP'S 15,567.59 KW OF NEM INSTALLATIONS** |
| GENERATION CAPACITY | **RESIDUAL CAPACITY VALUE OF A NEW** | **HOURLY ALLOCATION FACTORS CALCULATED** |

[1] See appendix C in http://www.cpuc.ca.gov/NR/rdonlyres/BD9EAD36-7648-430B-A692-8760FA186861/0/CPUCNEMDraftReport92613.pdf for E3's avoided cost methodology used in California and the history of its use and adoption.

| | | |
|---|---|---|
| | **SIMPLE-CYCLE COMBUSTION TURBINE** | **AS A PROXY FOR LOLP BASED ON SYSTEM LOADS & OUTPUT FROM PV WATTS** |
| ANCILLARY SERVICES | **ANCILLARY SERVICE UNIT COSTS PROVIDED BY RMP AND FERC FILINGS** | **GEOGRAPHIC SPECIFIC POWER OUTPUT FROM NREL'S PV WATTS MODEL FOR RMP'S 15,567.59 KW OF NEM INSTALLATIONS** |
| T&D CAPACITY | **DISTRIBUTION PROJECT UPGRADE COSTS PROVIDED BY RMP, LEVELIZED TO AN ANNUAL BASIS** | **HOURLY ALLOCATION FACTORS BASED ON HOURLY RESIDENTIAL PEAK LOADS & OUTPUT FROM PV WATTS** |

To calculate the hourly and annual generation from the 15,567.59 kW of installed NEM facilities at the time of the study, aggregate NEM system capacity for the most populous city of each county was inputted into NREL's PV Watts model. Table A2 lists the counties and NEM system capacities, which were inputted into PV Watts.[2]

*Table A2. NEM System Capacity per County*

| COUNTY | SUM OF PV (KW) |
|---|---|
| BEAVER | **30.55** |
| BOX ELDER | **79.68** |
| CACHE | **160.55** |
| CARBON | **21.63** |
| DAVIS | **637.59** |
| DUCHESNE | **0** |
| EMERY | **49.05** |
| GARFIELD | **0.6** |
| GRAND | **237.31** |
| IRON | **185.67** |
| JUAB | **10.36** |
| SALT LAKE | **8880.38** |
| MILLARD | **3.8** |
| MORGAN | **6.38** |
| PIUTE | **26** |
| RICH | **13.65** |

[2] Available at http://pvwatts.nrel.gov/

| | |
|---|---|
| SAN JUAN | **158** |
| SANPETE | **31.43** |
| SEVIER | **372.24** |
| SUMMIT | **592.44** |
| TOOELE | **263.99** |
| UINTAH | **102.06** |
| UTAH | **800.6** |
| WASATCH | **2.04** |
| WASHINGTON | **587** |
| WEBER | **2314.59** |
| | |
| TOTAL | **15567.59** |

## Data and Sources

The following data and sources have been used:

*Table A3. List of data used and data sources for this testimony*

| Data | Source |
|---|---|
| 2012 Rocky Mountain Power Heat Rates | Attach R746-700-23.c.8.g CONF.zip |
| PV Generation | NREL's PV Watts |
| Hourly Generation / Load Order | Attach R746-700-23.c.8.p - ThermalGasWind_CAS_Hryl Owned Gen (Jan 2012-Dec2012) CONF.xlsx |
| 2012 Statewide Loss Factor | Attach R746-700-23-C.8.m |
| Test Year Period Fuel Prices | Attach R746-700-23.C.1 -1 CONF.xlsm |
| Simple CT Plant Lifetime | 2013 Rocky Mountain Power Integrated Resource Plan, table 7.2 |
| Instant Cost of CT Plant | US Energy Information Administration - Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants - Table 1 - http://www.eia.gov/forecasts/capita |
| Variable O&M Costs | US Energy Information Administration - Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants - Table 1 - http://www.eia.gov/forecasts/capita |
| WACC | Exhibit_RMP_SRM3.pdf, page 2.1 |
| Escalation Rate | Average of June 2015 Operation and Maintenance Factors in Exhibit RMP_SRM4 CONF.xlsx |
| Insurance Costs | E3 CPUC NEM Avoided Cost Draft Report (09/2013) |
| Gas Prices | Average of Attach R746-700-23.C.1 -1 CONF.xlsm |
| Real-time Energy Prices | Fuel Price and Index Fcst Master from R746-700-23.C.8.f |
| Utility Discount Rate (WACC) | Exhibit_RMP_SRM_3.pdf, page 2.1 |
| Forecasted Net Metering Bills | Exhibit_RMP_JRS_8.pdf |
| Top 250 Load Hours | Attachment Sierra Club 3.18 |
| Net Metering kWh | Exhibit_RMP_JRS_8.pdf |
| Historical Mid-Columbia and COB Day Ahead Prices | FERC - Northwest Electric Market: Annual Bilateral Prices |
| Substation Capacity | Attachment Sierra Club 5.3 |
| Foreward Gas Prices (Gadsby, Lakeside, Currant Creek) | Fuel Price and Index Fcst Master from R746-700-23.C.8.f - CONF |
| Foreward Gas Prices (Hermiston, Chehalis) | Fuel Price and Index Fcst Master from R746-700-23.C.8.f - CONF - Henry Hub Prices |
| Risk Free Rate | 30 Year US Treasury Yield on 5/5/2014 |
| Distribution Investment Lifetime | E3 CPUC NEM Avoided Cost Draft Report (09/2013) - page C-40 |
| Instant Cost of Distribution Projects | Response to Sierra Club Data Request 3.23 |
| Emissions Factor | eGrid Utah Emissions Factors for WECC Rockies RMPA - http://www.epa.gov/ttn/chief/conference/ei20/session3/adiem.pdf |
| NEM Growth Rate | EIA Annual Energy Outlook 2014 - Table A16 |

## Analysis Horizon

The analysis was conducted over two time periods: the test year (July 2014 – June 2015), and the years 2015-2040. The assumptions and methods for both time periods are the same, with the exception that for the years 2015-2040, the following assumptions are made:

- NEM PV installations grow at a rate of 6.8% per annum
- Output of NEM PV installations is reduced by 0.5% per annum due to panel degradation

- NEM Charges remain constant at $4.25 / customer bill

**Avoided Cost of Energy**

The avoided cost of energy is calculated by:

1. Deriving hourly heat rates for each thermal plant operated by RMP using monthly heat rates supplied by RMP for each of their thermal generation fleet in R746-700-23.c.8.g, where the hourly heat rate for each hour of each month is the same as the heat rate for that month.
2. Deriving hourly fuel prices for each thermal plant operated by RMP using fuel prices from R746-700-23.C.1, where the hourly fuel price for each hour of each month is the same as the fuel price for that month.
3. Selecting an alternative generation scenario, which represents the thermal power plant and turbine whose generation the NEM PV installations are replacing.
4. For the selected alternative generation scenario:

$ACE_h = HR_h \text{ x } FP_h \text{ x } PV_h \text{ x } LF$

Where,

$ACE_h$ = Avoided Cost of Energy for hour *h*
$HR_h$ = Heat Rate for selected thermal plant for hour *h*
$FP_h$ = Fuel Price for selected thermal plant for hour *h*
$PV_h$ = PV Generation from all NEM PV installations
LF = Utah Statewide Loss Factor from R746-700-23-C.8.m

5. All hourly results from step 4 are summed over the determined time period, resulting in an annual or multi-year avoided cost of energy value.

*Alternative Generation Scenarios*
For the test year period, the following alternative generation scenarios are available:

- Hermiston
- Chehalis
- Lake Side
- Gadsby 1
- Gadsby 2
- Gadsby 3
- Gadsby 4
- Gadsby 5
- Gadsby 6
- Currant Creek
- Hungtington 1

- Hungtington 2
- Hunter 1
- Hunter 2
- Hunter 3
- Carbon 1
- Carbon 2
- Wyodak
- Naughton 1
- Naughton 2
- Naughton 3
- Cholla
- Colstrip
- Jim Bridger
- Dave Johnston 1
- Dave Johnston 2
- Dave Johnston 3
- Dave Johnston 4
- Calculated Loading Order
- RMP's Natural Gas Plants
- All Coal

Heat rates for certain turbines in certain months (i.e. Gadsby 1,2,3 in January) were not available; for such alternative generation scenarios the model has not been run.

*Calculated Loading Order*

In this alternative generation scenario, a loading/dispatch order has been reconstructed. Hourly generation data of the Company's Thermal Fleet is used from the Company's GRC filings, which has been filed in accordance with Utah Administrative Code R746-700-23-C.8.p. This data has been used as part of the Company's Power Cost Modeling (PCM). The hourly incremental change (increase or decrease) in the power output of each generating unit is calculated. For hours in which the change is positive, it is assumed the Company and/or it's PCM model has found it optimal to increase the generation from such resource. For each hour, nominal amounts of increased power output (MW) are calculated for each unit. These nominal amounts are then divided by the total amount of increased power output from those units whose output has increased. As part of determining the avoided cost of energy under a total thermal resource dispatch scenario, these ratios are used in combination with fuel prices and each unit's hourly heat rate to determine a weighted avoided cost of energy.

*RMP's Natural Gas Plants*

In this alternative generation scenario, the average hourly heat rates for all of RMP's natural gas turbines is calculated and used.

*All Coal*

In this alternative generation scenario, the average hourly heat rates for all of RMP's coal fired power plants is calculated and used.

**Generation Capacity Value**

The generation capacity value has been adapted from E3's NEM Avoided Cost Calculated and calculates the value of capacity using a new combustion turbine as the proxy resource for capacity. The value of capacity is calculated as the capacity residual: the real annualized cost of a new CT less the annual net revenues that generator could earn through participation in the real-time energy and ancillary services markets. It is calculated as:

$$GCV_h = GenCap_y \text{ x } GenWt_h * LF$$

Where,

$GenCap_y$ = Generation Capacity Cost in year *y*
$GenWT_h$ = Generation Capacity Allocation Factor for hour *h*
LF = Utah Statewide Loss Factor from R746-700-23-C.8.m

Generation Capacity Cost is calculated by:

$$GenCap_y = (CT_y – (EMargin_y + ASMargin_y))$$

Where,

$CT_y$ = Levelized cost of a simple cycle combustion turbine in year *y*
$EMargin_y$ = Margins earned by the new CT in real-time energy market in year *y*
$AMargin_y$ = Margins earned by the new CT from the ancillary service markets

Margins earned by the new CT in real-time energy market are calculated by:

$$EMargin_y = RTMargin_y + ASMargin_y$$

Where,

$RTMargin_y$ = Sum of $(RTMkt_{y,h} – CT\_VC_{y,h})$ for all hours where $RTMkt_{y,h} > (1+BidFctr)* CT\_VC_{y,h}$

$CT\_VC_{y,h}$ = Full variable cost of CT operation for hour *h* in year *y*
= $\text{Heat rate}_m * GasPrice_m * VarOM_y$

$Heat\ rate_m$ = Hourly average heat rate of RMP's natural gas plants for month *m*
$GasPrice_m$ = Hourly average fuel price for RMP's fuel prices for natural gas plants for month *m*
$VarOM_y$ = Variable O&M cost escalated to year *y* by escalation rate *r*
BidFctr = Assumed profit margin included in CT bid prices (10%)
$ASMargin_y$ = Ancillary service margin

$GenWT_h$, the Generation Capacity Value Allocation Factor, is calculated as follows:

*Loss of Load Probability*

1. The top 250 forecasted hourly loads for Utah residential class customers are taken from Attachment Sierra Club 3.18.
2. The top 249 highest loads are subtracted from the highest load, which is calculated as by taking the peak hourly load and multiplying that by RMP's planned reserve margin (13%). The results are then summed.
3. To obtain the inverse, each difference between the peak load in the top 249 hourly loads is then subtracted from the sum in step 2. These results are summed.
4. Each individual result for the top 249 hours in step 3 is then divided by the summed result from step 3 to result in a LOLP weighting mechanism, where the smaller the difference between the peak load and the hourly load, the greater the weighting. [This weighting is then multiplied by the generation capacity cost, the NEM generation in each hour, and the peak capacity loss factor.

This allocation methodology has been adapted from E3's methodology for allocating Generation Capacity value in their Avoided Cost Calculator.[3]

**Ancillary Services Value**

Ancillary Services value is calculated by:

$$ASValue_y = PV_y \text{ x } ASCost_{kwh}$$

Where,

$PV_y$ = Annual PV Generation from all NEM PV installations, in kWh
$ASCost_{kwh}$ = the average $ spent on Ancillary Services per kWh sold in Utah spent by RMP for years 2010-2013

**Transmission and Distribution Capacity Value**

Transmission and Distribution Capacity Value is calculated by:

[3] Available at: https://ethree.com/documents/CPUCDR/DR_MethodologyDetail%20v2.doc

1. Based on the capacities (kW) and prices for planned distribution projects provided from RMP in 3.23, average $/kW of distribution capacity increase value are calculated.
2. This $/kW cost (plus cost of capital) is levelized over 15 years (expected life of distribution project)
3. The standard deviation of hourly residential class loads is taken to create a threshold.
4. This threshold is subtracted from each hourly load, and the differences are summed. The individual difference between the standard deviation threshold and the hourly load divided by this sum is the allocation factor (the greater the load over the threshold, the greater the factor; giving more weight to hours when distribution is theoretically most strained)
5. This allocation factor is multiplied by the levelized $/kW cost times the PV generation for each hour.

Since data was not available to determine the length of time distribution projects are deferred due to reduction in load, this calculation assumes that each kW of NEM PV distribution substation capacity upgrades can effectively serve as a deferral for an equivalent kW of substation capacity. T&D capacity costs are levelized to achieve an annual cost.