BP-20 Rate Case Workshop: Generation Inputs

September 12, 2018

Agenda

- Balancing Reserve Forecast
- Solar Modeling
- Application of ISD for Balancing Reserve Allocation

Balancing Reserve Forecast

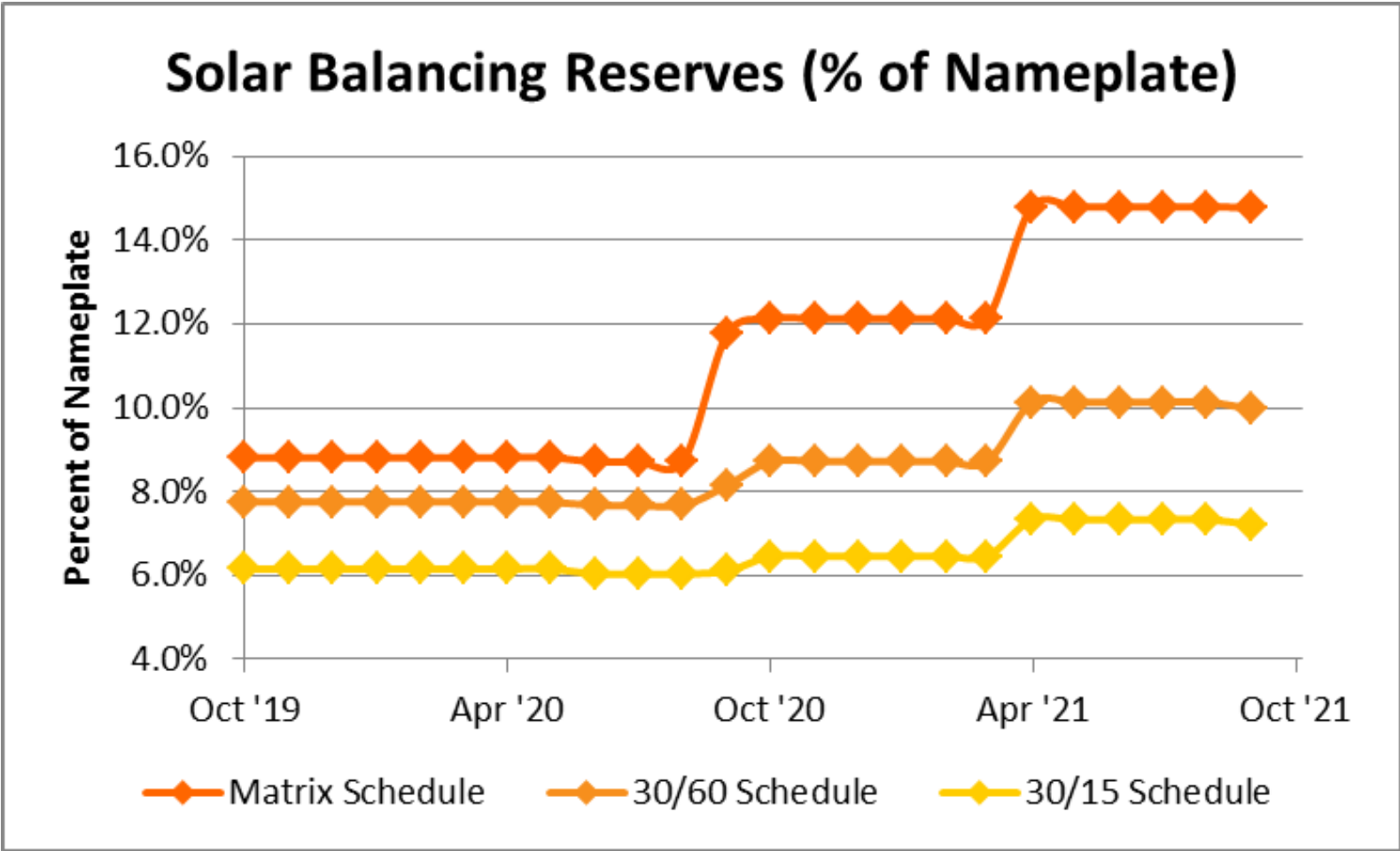# Forecasted Generation Profile
(MW of Installed Capacity)

Month	Wind	Solar	DERs	CGS	Hydro
Oct '19	2767	148	1608	1230	2527
…	…	…	…	…	…
Jun '20	2967	148	1608	1230	2527
…	…	…	…	…	…
Sept '20	2967	248	1608	1230	2527
Oct '20	3269	268	1608	1230	2527
…	…	…	…	…	…
Apr '21	3269	361	1608	1230	2527
…	…	…	…	…	…
Sept '21	3473	361	1608	1230	2527

Total INC Reserve Capacity by Type (MW of Balancing Reserves)

Month	Total	Load	Wind	Solar	FCRPS	DERs
Oct '19	686	260	389	13	15	8
…	…	…	…	…	…	…
Jun '20	720	261	423	13	15	8
…	…	…	…	…	…	…
Sept '20	728	258	418	29	15	8
Oct '20	773	260	459	32	15	8
…	…	…	…	…	…	…
Apr '21	780	256	451	52	14	8
…	…	…	…	…	…	…
Sept '21	795	255	466	52	14	7

Total DEC Reserve Capacity by Type (MW of Balancing Reserves)

Month	Total	Load	Wind	Solar	FCRPS	DERs
Oct '19	-834	-292	-497	-16	-19	-10
…	…	…	…	…	…	…
Jun '20	-880	-293	-543	-16	-19	-10
…	…	…	…	…	…	…
Sept '20	-874	-286	-524	-37	-18	-9
Oct '20	-947	-289	-590	-41	-18	-9
…	…	…	…	…	…	…
Apr '21	-944	-282	-570	-66	-17	-9
…	…	…	…	…	…	…
Sept '21	-964	-281	-591	-66	-17	-9

Pre-decisional. For discussion purposes only.

Solar Balancing Reserves (% of Nameplate)

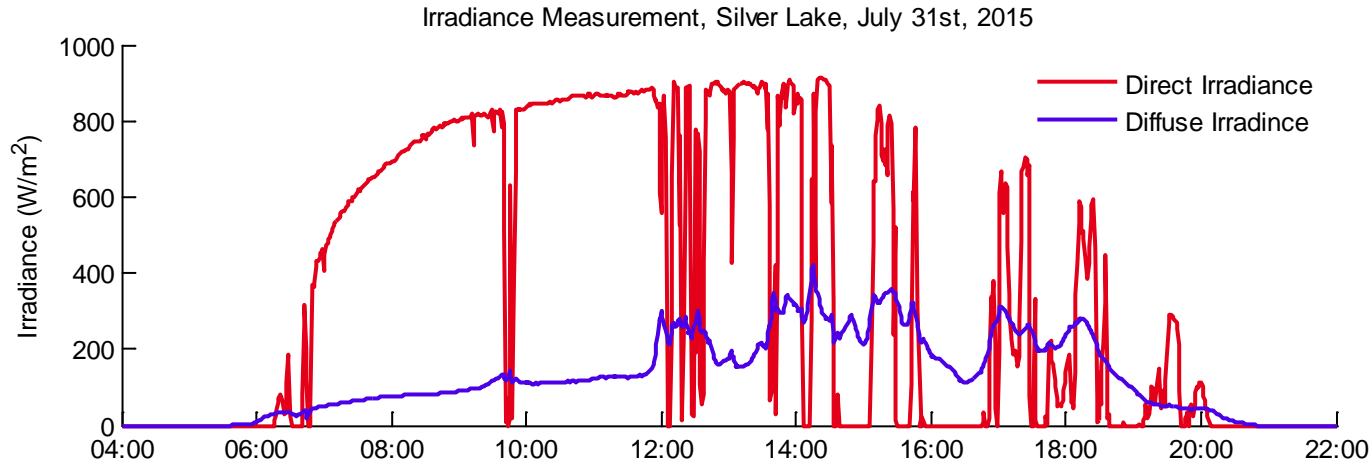Average = 11.2%   Average = 8.6%   Average = 6.5%

Solar Modeling

Inverter Loading Ratio (ILR)

- Ratio of DC Nameplate to AC Nameplate
  - DC Nameplate – capacity of DC system based on number of PV panels
  - AC Nameplate – capacity of DC-to-AC inverter
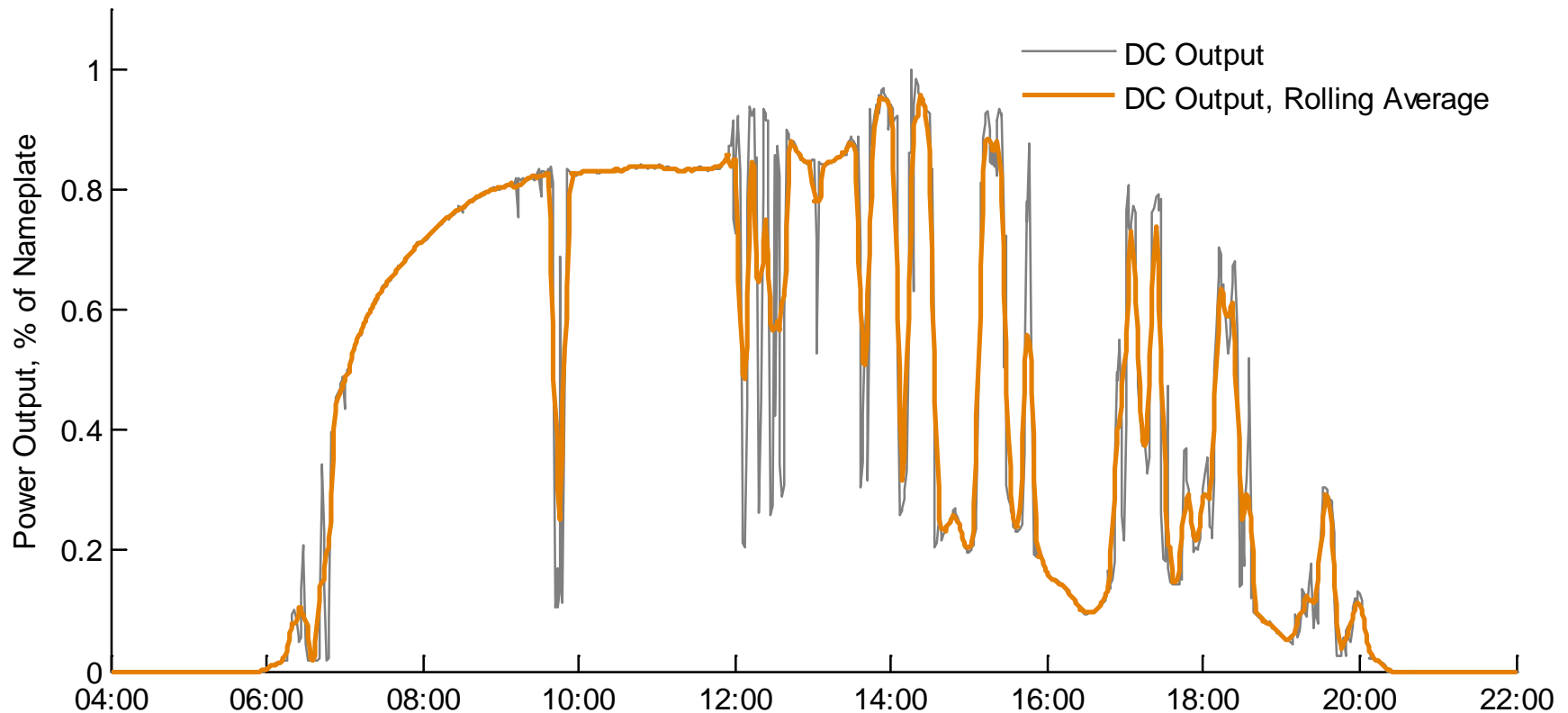
Calculate DC Power from Irradiance
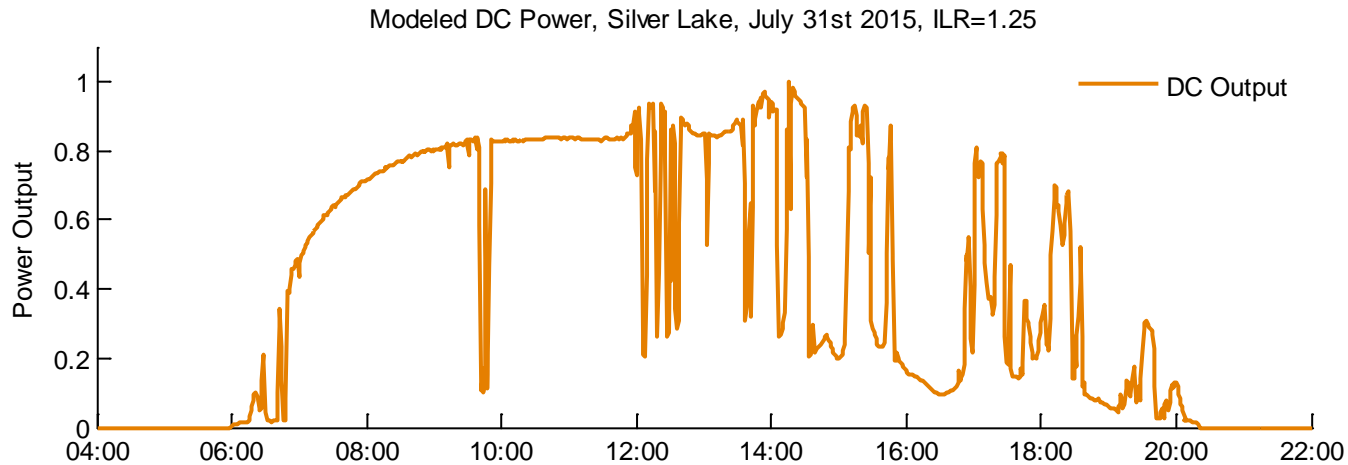
- For process, see appendix 1

Irradiance Measurement, Silver Lake, July 31st, 2015

Modeled DC Power, Silver Lake, July 31st 2015, ILR=1.25

Scale and Shift for Proposed Plants

- For process, see appendix 2

Modeled DC Power for 100 MW Plant, Silver Lake, July 31st 2015, ILR=1.25

Limit to AC Nameplate
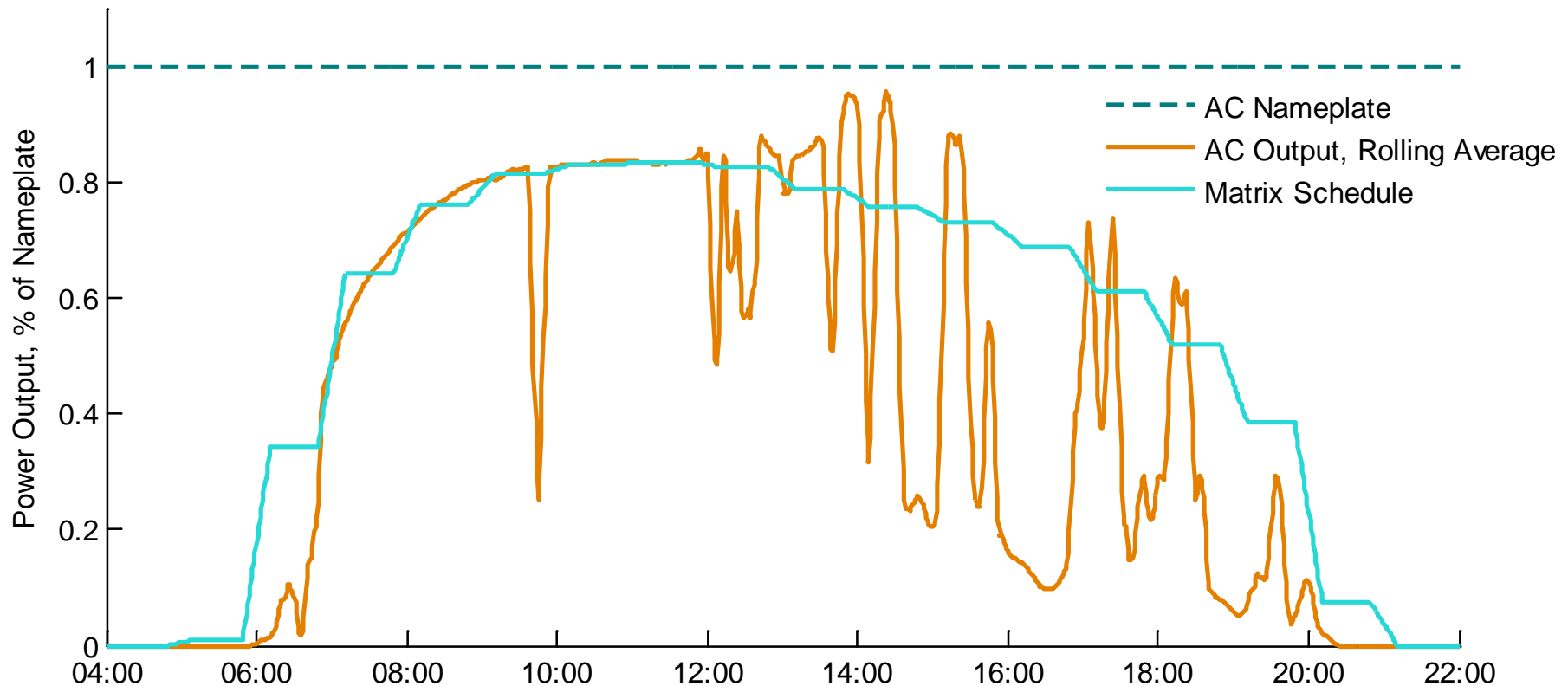
- DC output clipped to AC nameplate

Modeled AC Power for 100 MW Plant, Silver Lake, July 31st 2015, ILR=1.25
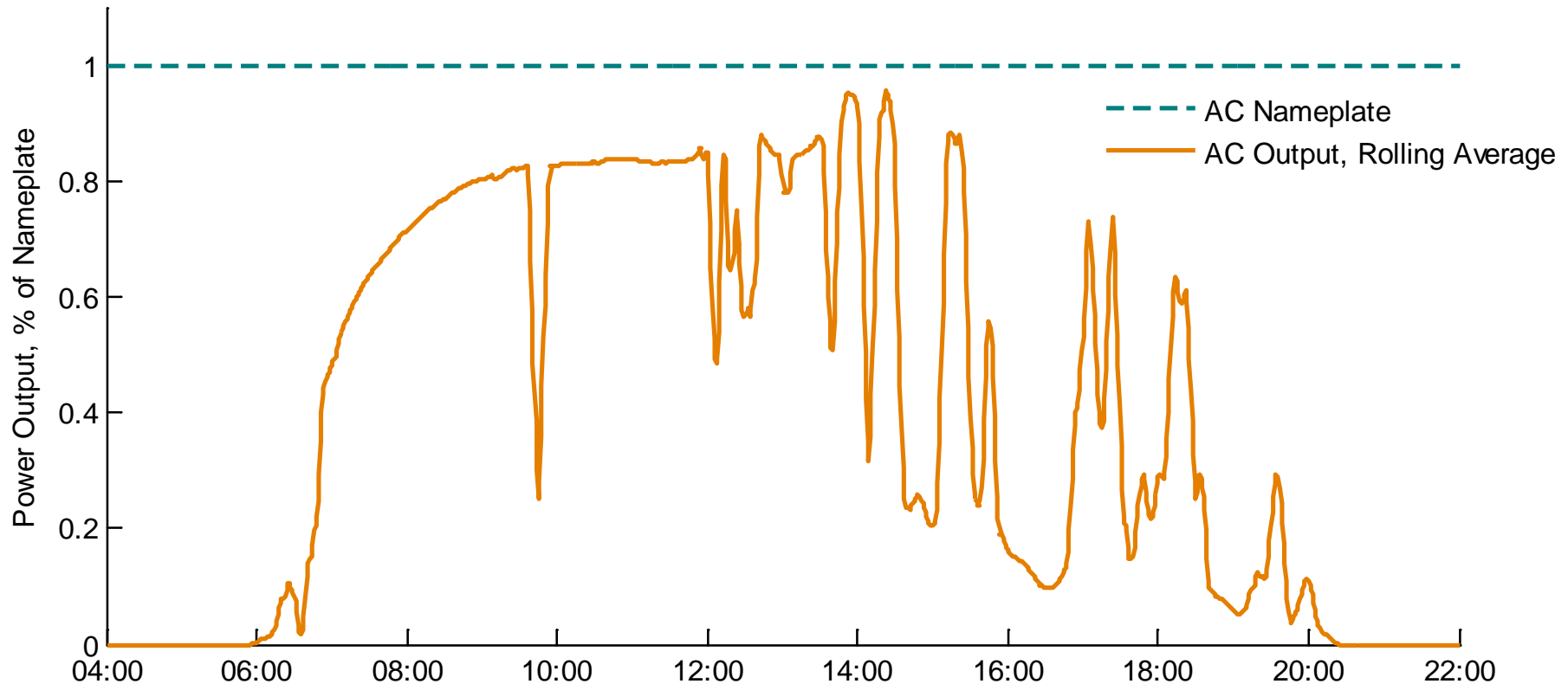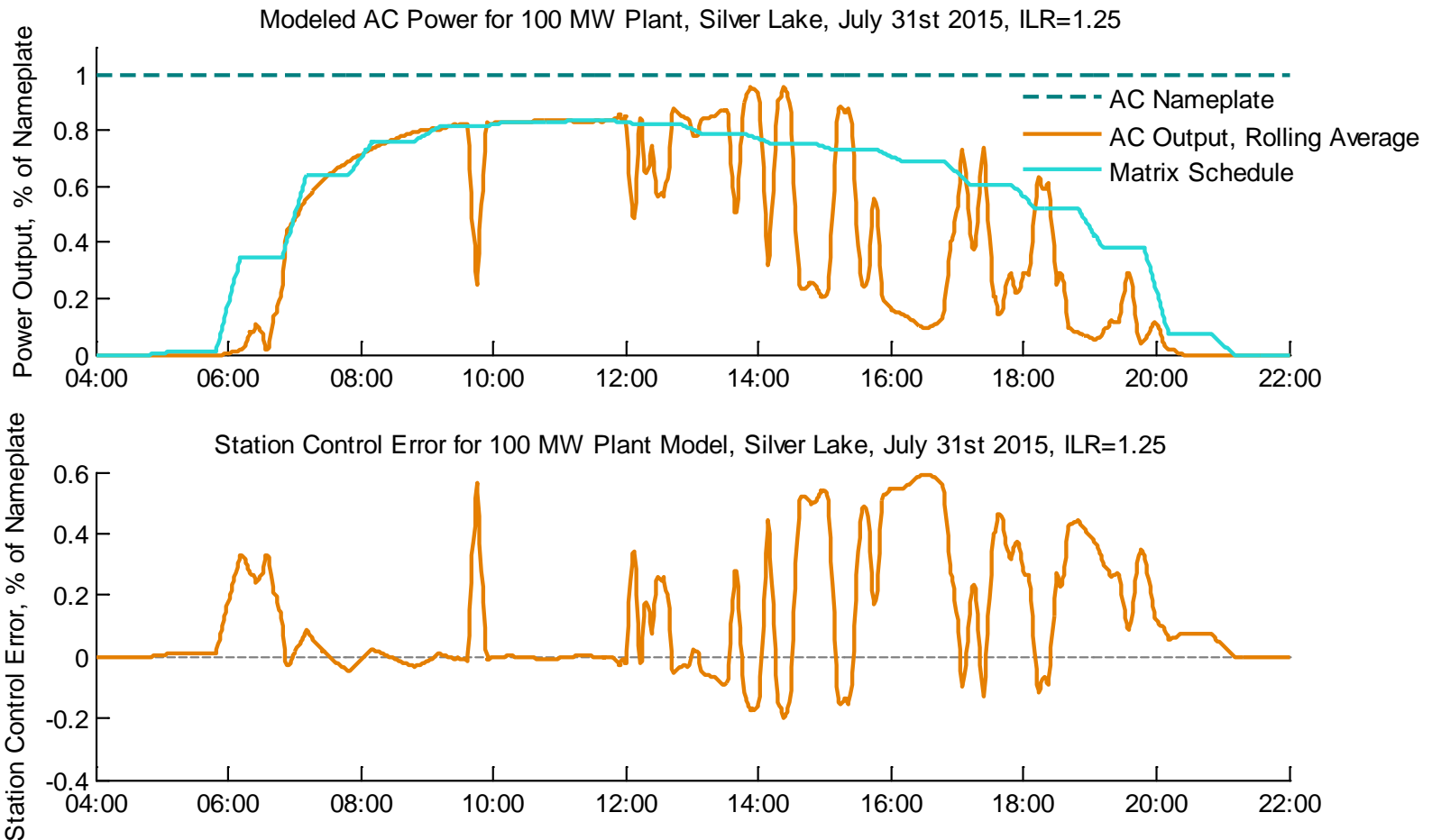
Create Schedule

- For matrix schedule creation, see appendix 3

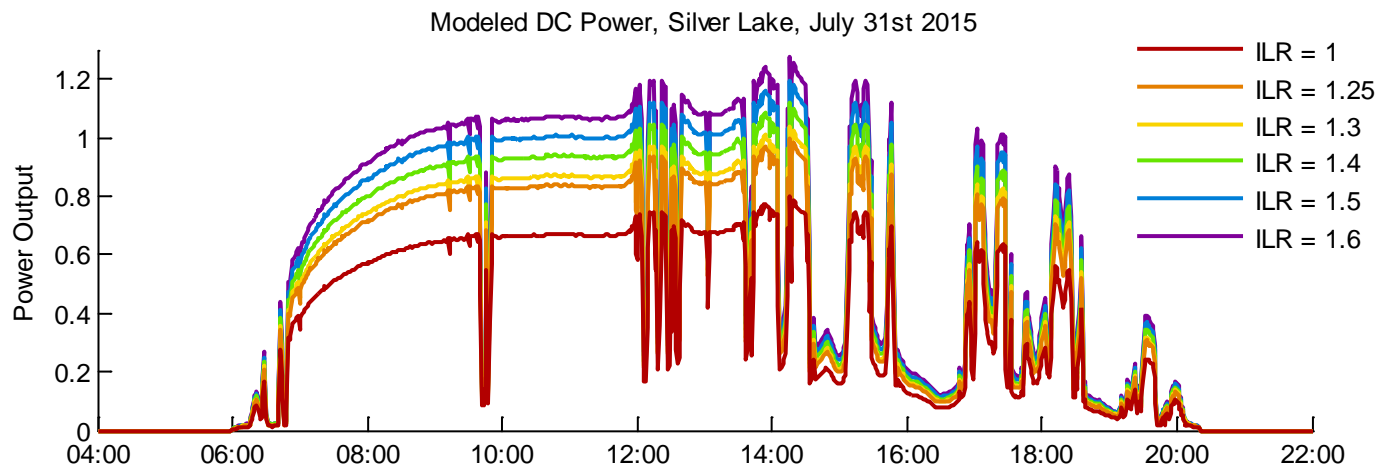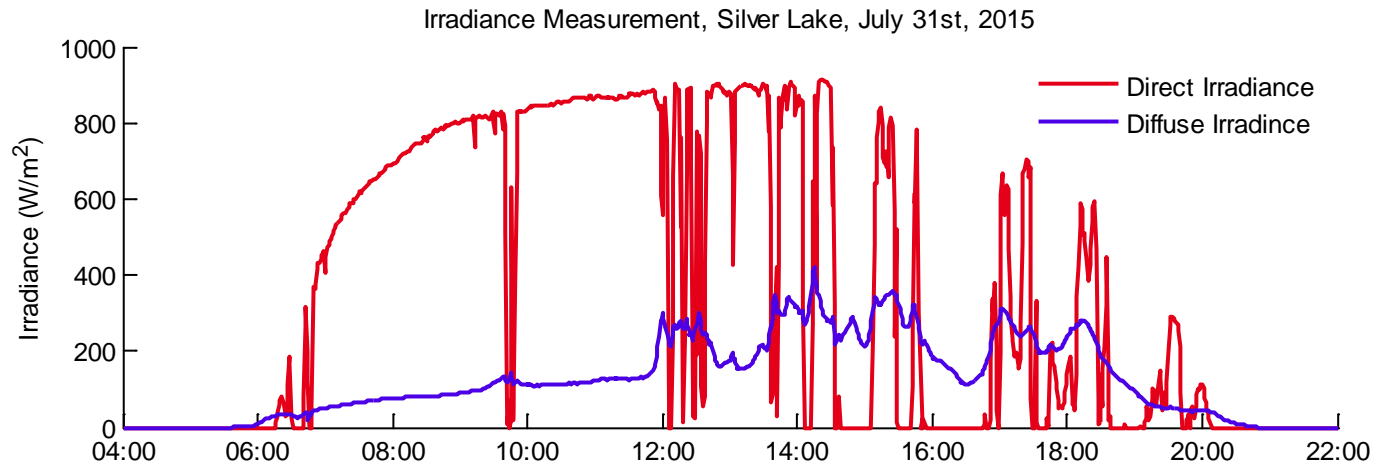Modeled AC Power for 100 MW Plant, Silver Lake, July 31st 2015, ILR=1.25

Calculate Station Control Error

- ## Station Control Error = Schedule – Generation

Modeled AC Power for 100 MW Plant, Silver Lake, July 31st 2015, ILR=1.25

Station Control Error for 100 MW Plant Model, Silver Lake, July 31st 2015, ILR=1.25

Calculate DC Power from Irradiance

- For process, see appendix 1

Irradiance Measurement, Silver Lake, July 31st, 2015

Modeled DC Power, Silver Lake, July 31st 2015
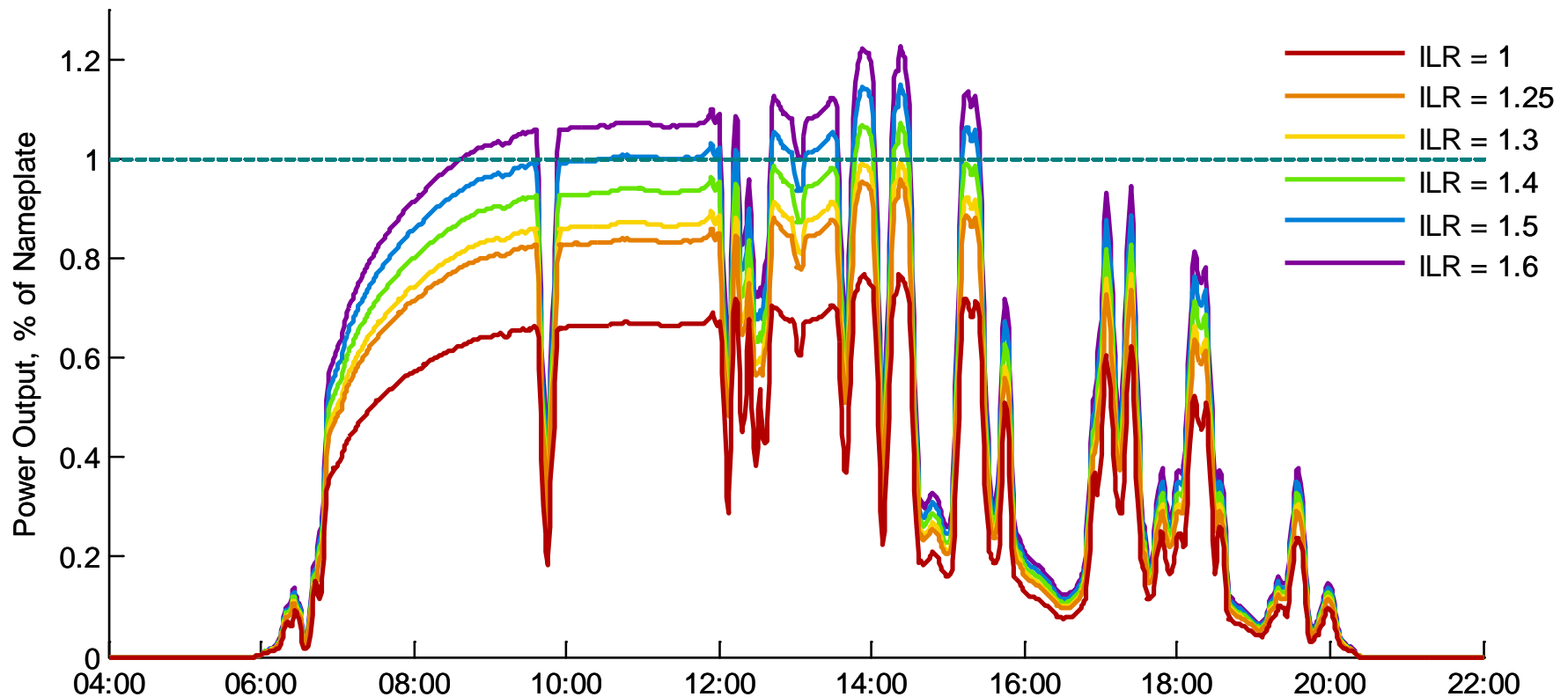
Scale and Shift for Proposed Plants
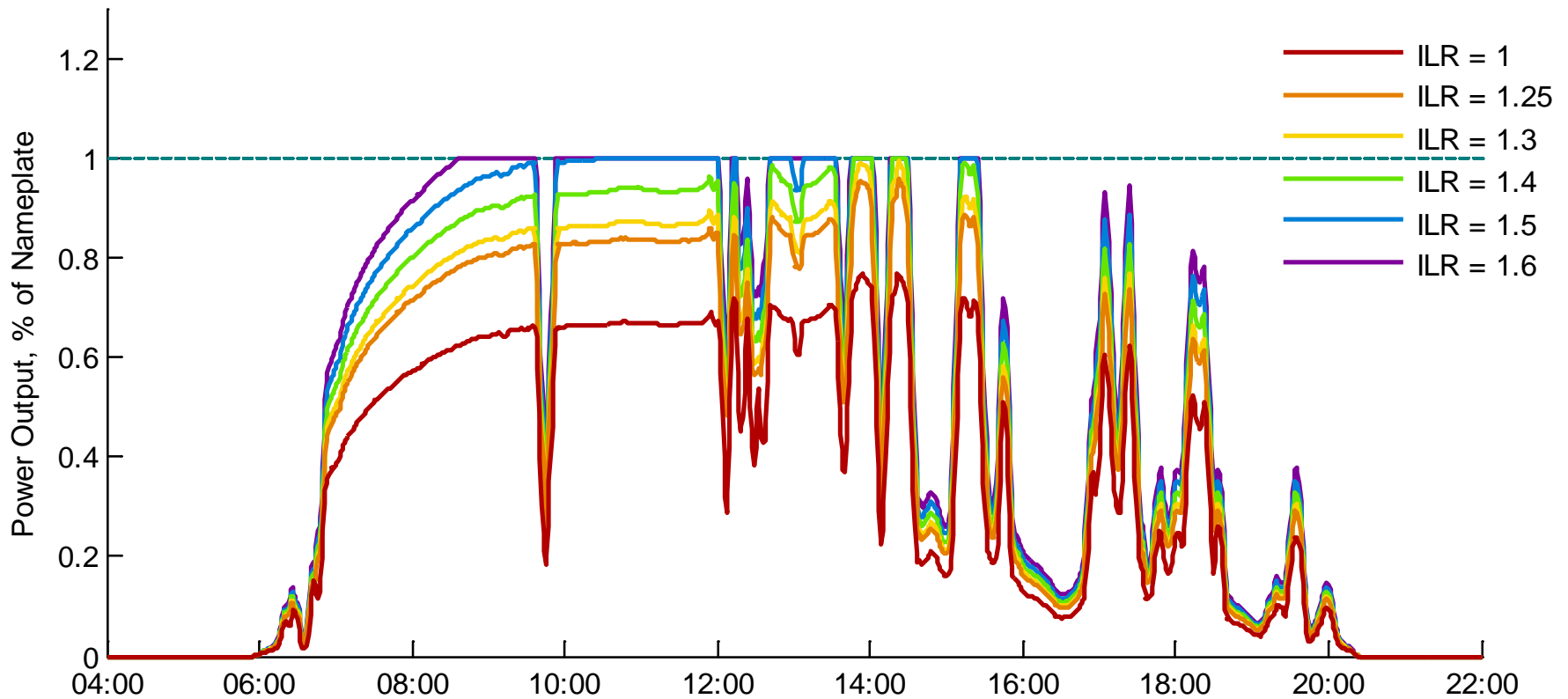
- For process, see appendix 2

Modeled DC Power for 100 MW Plant, Silver Lake, July 31st 2015

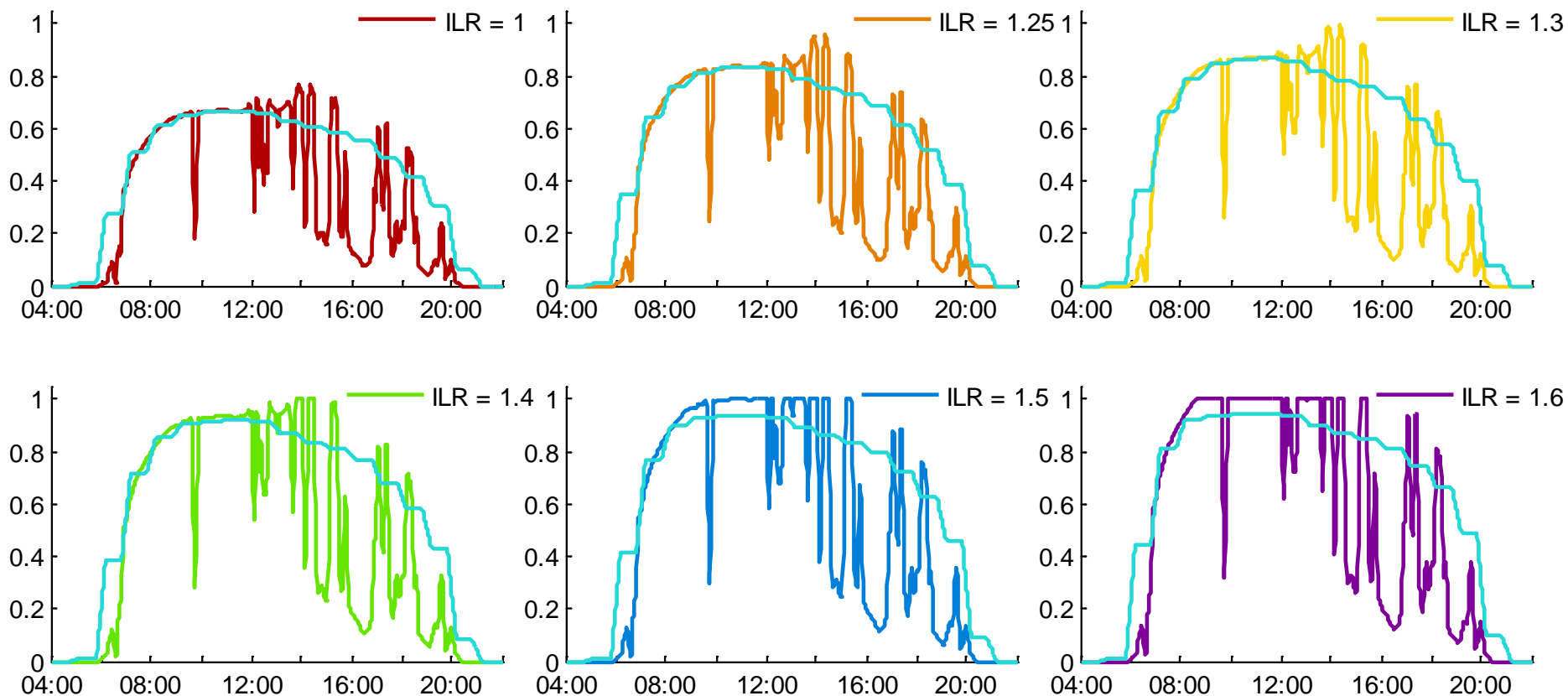# Limit to AC Nameplate

- DC output clipped to AC nameplate

Modeled AC Power for 100 MW Plant, Silver Lake, July 31st 2015
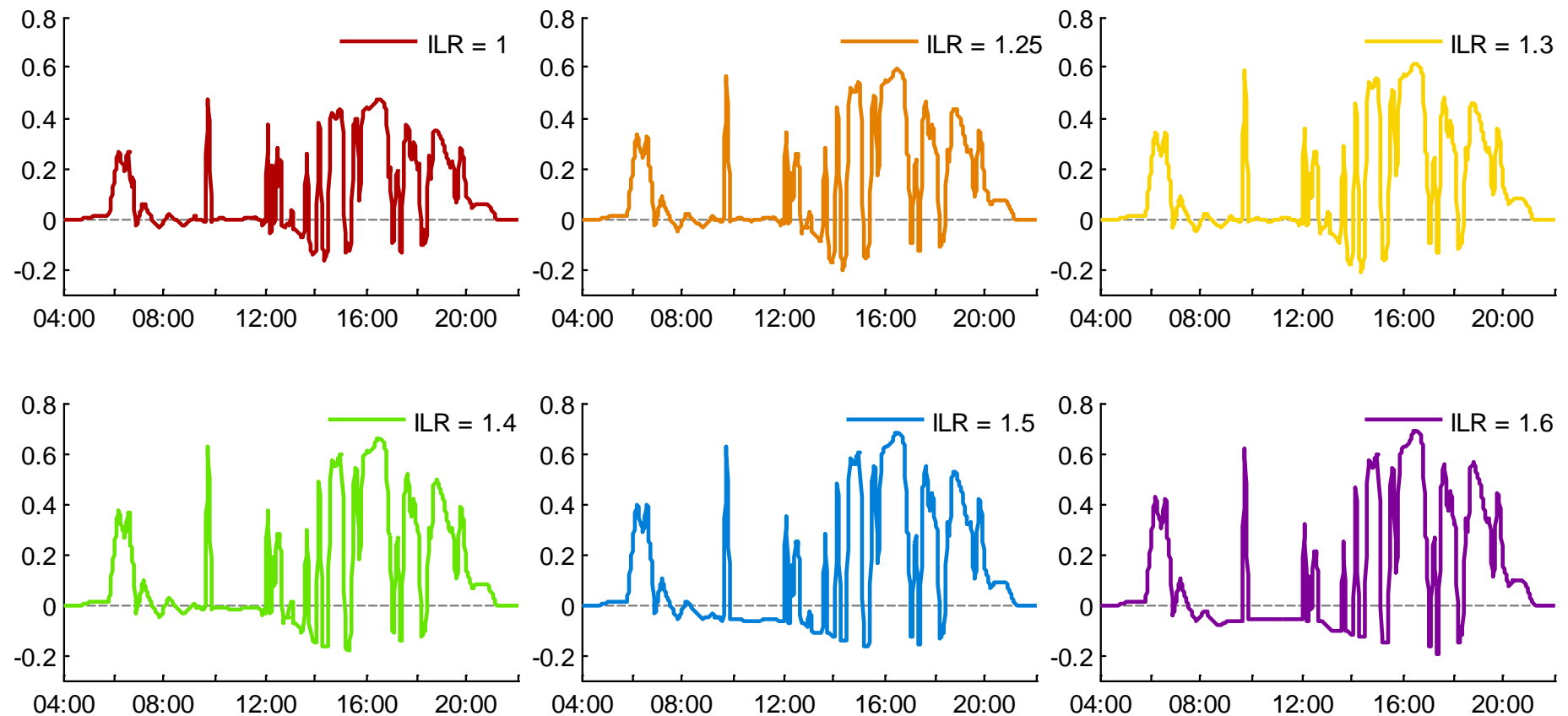
Create Schedule

- For matrix schedule creation, see appendix 3
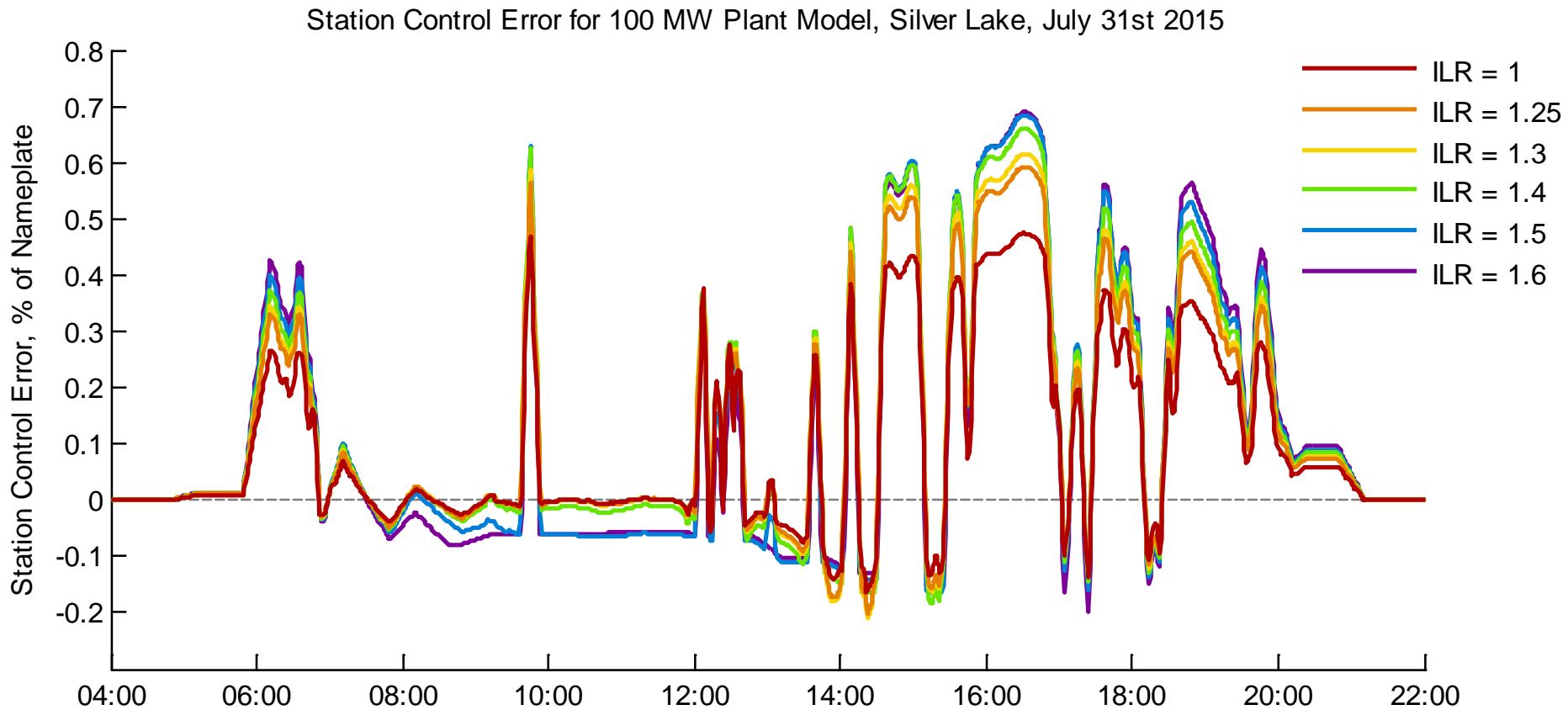
Calculate Station Control Error

- Station Control Error = Schedule – Generation

Calculate Station Control Error

- ## Station Control Error = Schedule – Generation

Station Control Error for 100 MW Plant Model, Silver Lake, July 31st 2015

Inverter Loading Ratio Impact Comparison

- ## Percent of Minutes Clipped at Various ILRs for each Solar Data Sensor Location

ILR	Bend, OR	Burns, OR	Cheney, WA	Hermiston, OR	Silver Lake, OR
1	0.00%	0.00%	0.00%	0.00%	0.00%
1.25	1.56%	0.43%	0.12%	0.10%	0.56%
1.3	2.70%	1.02%	0.25%	0.18%	1.31%
1.4	6.39%	4.68%	1.25%	0.99%	5.54%
1.5	10.19%	9.17%	4.47%	4.69%	10.41%
1.6	13.09%	12.86%	8.41%	9.01%	14.05%
2	19.84%	21.37%	17.52%	18.31%	22.07%

Inverter Loading Ratio Impact Comparison

- Average Solar Balancing Reserves as Percent of Nameplate Across Rate Period at Various ILRs

ILR	30-15	30-60	Matrix
1	5.0%	6.5%	8.2%
1.25	6.5%	8.6%	11.2%
1.3	6.9%	9.1%	12.0%
1.4	7.7%	10.1%	13.4%
1.5	8.3%	11.1%	14.6%
1.6	8.9%	12.0%	15.6%
2	10.7%	15.1%	17.4%

Application of ISD for Balancing Reserve Allocation

Netted Error by Group

Summed Netted Error

Divide into 24, hour-based sets

Pre-decisional. For discussion purposes only.
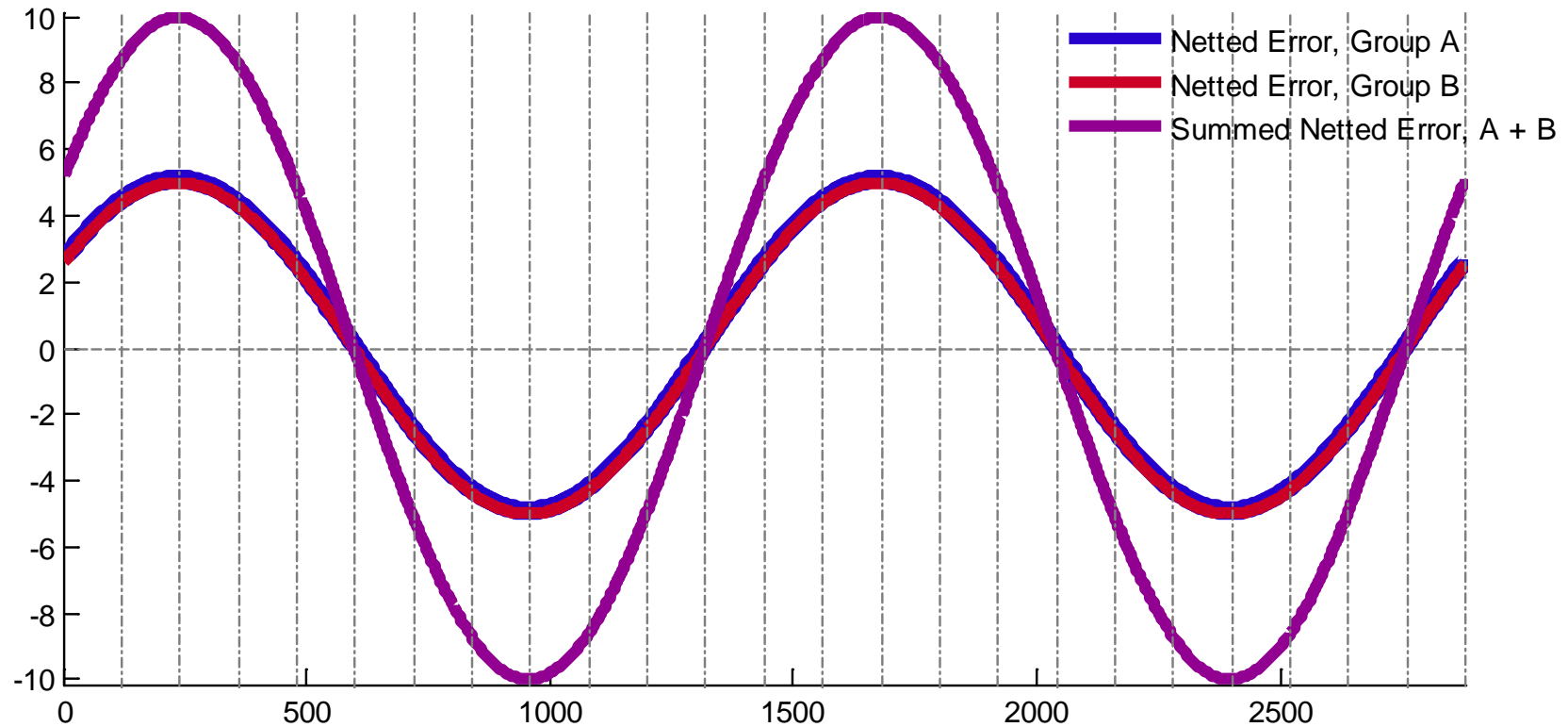
Determine 24 ISD Allocations

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Group A Allocation	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Group B Allocation	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5

Pre-decisional. For discussion purposes only.

Identify maximum allocation per group

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Group A Allocation	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Group B Allocation	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5

Group A Maximum Allocation	0.5
Group B Maximum Allocation	0.5

Calculate final allocation

- Weight to a total of 1 (divide by sum of max allocations)

Group A Maximum Allocation	0.5
Group B Maximum Allocation	0.5

Group A Final Allocation	0.5/1.0 = 0.5
Group B Final Allocation	0.5/1.0 = 0.5

Pre-decisional. For discussion purposes only.

Netted Error by Group
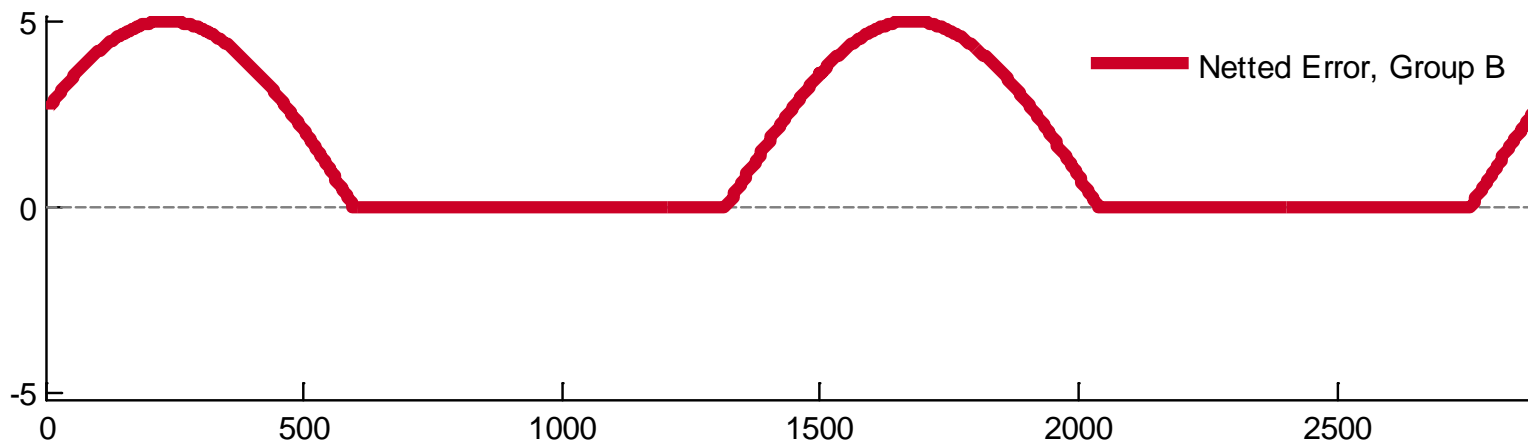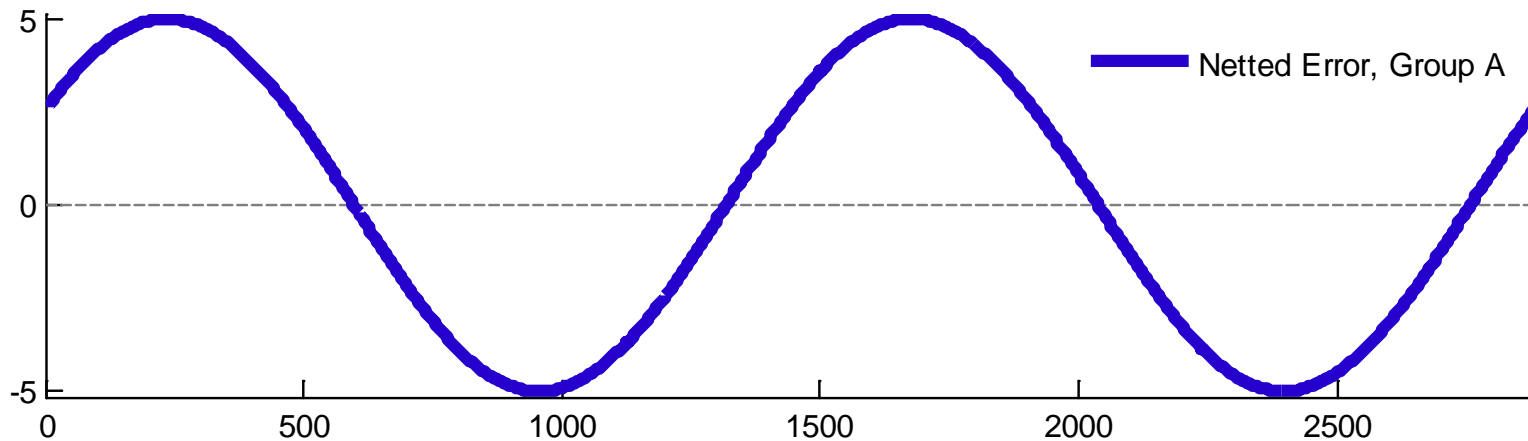
Summed Netted Error
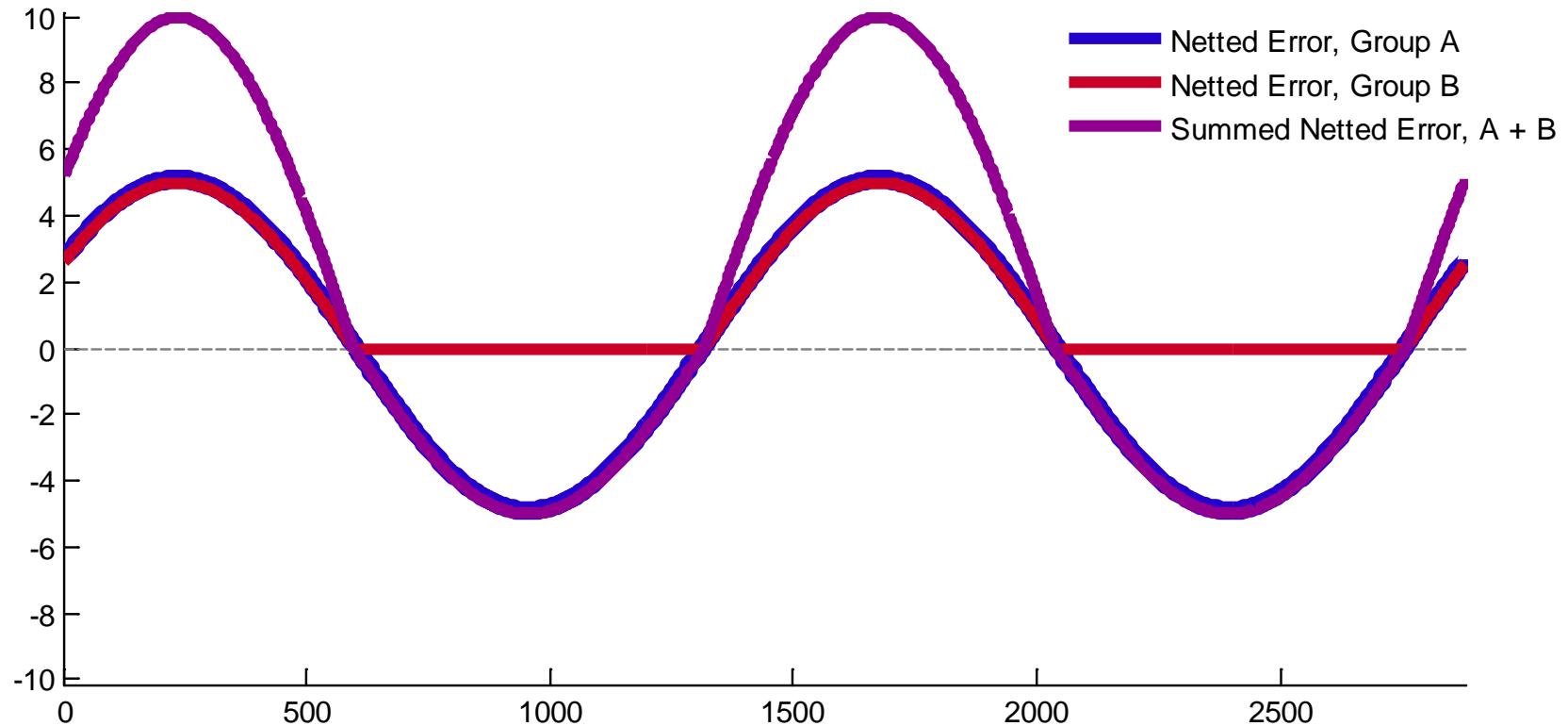
Divide into 24, hour-based sets

Determine 24 ISD Allocations
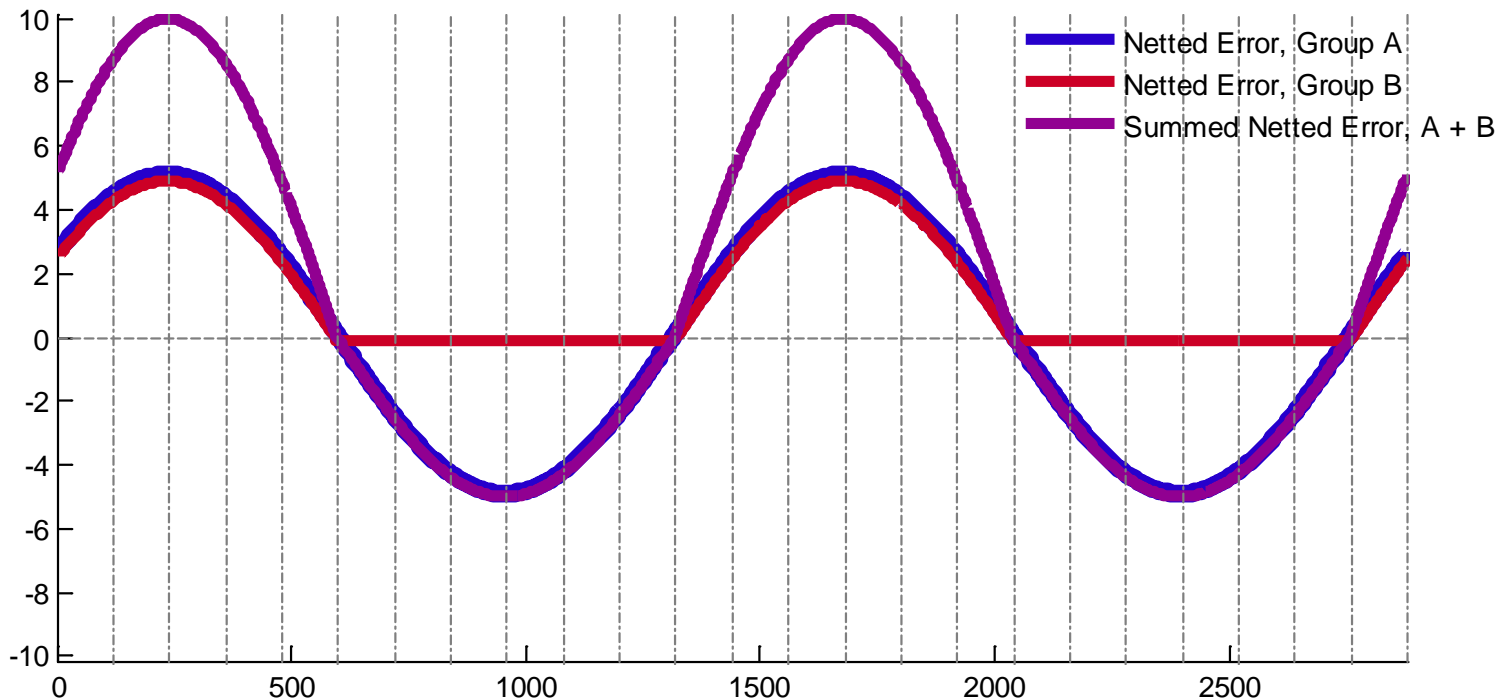
Legend:
- Netted Error, Group A
- Netted Error, Group B
- Summed Netted Error, A + B

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Group A Allocation	.5	.5	.5	.5	.5	1	1	1	1	1	1	.5	.5	.5	.5	.5	.5	1	1	1	1	1	1	.5
Group B Allocation	.5	.5	.5	.5	.5	0	0	0	0	0	0	.5	.5	.5	.5	.5	.5	0	0	0	0	0	0	.5

Identify maximum allocation per group

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Group A Allocation	.5	.5	.5	.5	.5	1	1	1	1	1	1	.5	.5	.5	.5	.5	.5	1	1	1	1	1	1	.5
Group B Allocation	.5	.5	.5	.5	.5	0	0	0	0	0	0	.5	.5	.5	.5	.5	.5	0	0	0	0	0	0	.5

Group A Maximum Allocation	1
Group B Maximum Allocation	0.5

Calculate final allocation

- Weight to a total of 1 (divide by sum of max allocations)

Group A Maximum Allocation	1
Group B Maximum Allocation	0.5

Group A Final Allocation	1/1.5 = 0.66
Group B Final Allocation	0.5/1.5 = 0.33

Appendix 1: Model Used to Calculate DC Power from Irradiance Data

Model Inputs

- Timestamped direct and diffuse irradiance sensor data and temperature data from University of Oregon
- Latitudes/longitudes of sensors
- DC nameplate (Currently modeling at 1.25x AC NP)
- AC nameplate
- Overall efficiency (0.83)
- Cell temperature coefficient (0.035)
- Temperature coefficient (0.004)

Step 1: Calculate day-of-year- and time-of-day-based parameters

- Equation of Time (ET) – correction factor used in Solar Time equation
    - $ET = 9.87 \sin(2B) - 7.53 \cos(B) - 1.5 \sin(B)$
        - $B = \frac{360(n-81)}{364^o}$
            - n=nth day of year
    - Equation 2.27 in Ref. 1

- Local Solar Time (ST) – Adjustment to local standard time (lst) based on longitude shift
    - $ST = lst + ET + 4(lon_{std} - lon_{local})$
        - Where lon_{std} is the standard time meridian (120°), lon_{local} is the longitude of the plant, and the 4 is in units of minutes/degree
    - Equation 2.26 in Ref. 1

- h_s – degrees from solar noon
    - $h_s = \frac{ST - 12*60}{4}$
    - Equation 2.25 in Ref. 1

Step 1: Calculate day-of-year- and time-of-day-based parameters cntd.

- δ_s – declination angle (Earth tilt angle)
  - $\delta_s = \sin^{-1}\left(23.45^o \cdot \sin\left(\frac{360 \cdot (284+n)}{365^o}\right)\right)$
    - n=nth day of year
  - Equation 2.23 in Ref. 1

- α – Solar altitude angle
  - $\alpha = \sin^{-1}(\sin(lon_{local})\sin(\delta_s) + \cos(lon_{local})\cos(\delta_s)\cos(h_s))$
  - Equation 2.28 in Ref. 1

- a_s – Solar azimuth angle
  - $a_s = \sin^{-1}\left(\frac{\cos(\delta_s)\sin(h_s)}{\cos(\alpha)}\right)$
  - Equation 2.29 in Ref. 1

Step 1: Calculate day-of-year- and time-of-day-based parameters cntd.

- β=ρ – tracking angle
    - $\beta = \rho = \tan^{-1}\left(\dfrac{\sin(a_s)}{\tan(\alpha)}\right)$
        - Assumes a north-south-oriented tracking axis
    - Equation 4.13 in Ref. 2

- θ_i – angle of incidence
    - $\theta_i = \cos^{-1}\left(\sqrt{1 - \left((\cos(\alpha))^2 \cdot (\cos(a_s))^2\right)}\right)$
        - Assumes a north-south-oriented tracking axis
    - Equation 4.14 in Ref. 2

Step 2: Calculate daily info for each day in dataset

- Extend day-based values from step 1 to a 1-minute resolution vector based on the days of our dataset

Pre-decisional. For discussion purposes only.

Step 3: Calculate total irradiance

- I_{dn} – Direct normal component of irradiance
  - $I_{dn} = \cos(\theta_i) \cdot (Direct\ Normal\ Sensor\ Data)$
  - Equation 2.47 in Ref. 1

- I_{df} – Diffuse component of irradiance
  - $I_{df} = \left(\cos\left(\frac{\beta}{2}\right)\right)^2 \cdot (Diffuse\ Sensor\ Data)$
  - Equation 2.49 in Ref. 1

- Ground-reflected solar is not measured by the sensors and is thus ignored

- I_t – Total irradiance
  - $I_t = I_{dn} + I_{df}$

Step 4: Convert from Irradiance to Power

- ## Cell temperature
  - $cell\ temp = temp + I_t \cdot cell\ temp\ coef$
  - Equation 1 in Ref. 4

- ## Temperature coefficient
  - $temp\ coef = 1 - temp\ coef_{static}(cell\ temp - 28)$
  - Equation 8 in Ref. 3

- ## Predicted DC power
  - $PP_{DC} = NP_{DC} \cdot Efficiency \cdot \dfrac{I_t}{1000} \cdot temp\ coef$
  - Equation 8 in Ref. 3

References

1) Goswami, Dr. Y et al. (2000). *Principles of Solar Engineering*. New York: Taylor and Francis Group
   - We have a physical copy of this but it can also be found in pdf form on the internet.

2) Stine, W and Geyer, M (2001). *Power From the Sun*. Retrieved from http://www.powerfromthesun.net

3) Dobos, A (2013). *PVWatts Technical Manual*. NREL
   - https://www.nrel.gov/docs/fy14osti/60272.pdf
      - Link to original version
   - https://www.nrel.gov/docs/fy14osti/62641.pdf
      - Link to updated version

4) Alonso Garcia, M.C. and Balenzategui, J.L. (2004). *Estimation of photovoltaic module yearly temperature and performance based on Nominal Operation Cell Temperature Calculations.*

Appendix 2: Scaling and Shifting DC Solar Power Data to Represent Proposed Plants

Scaling Methodology Development

- University of Oregon data is "point source" - a single irradiance sensor at each location

- We want to represent various sizes of solar farms

- Variability of the signal decreases as size of the plant increases, so we must pay attention to how we scale the data up from the single sensors to the representative plant data
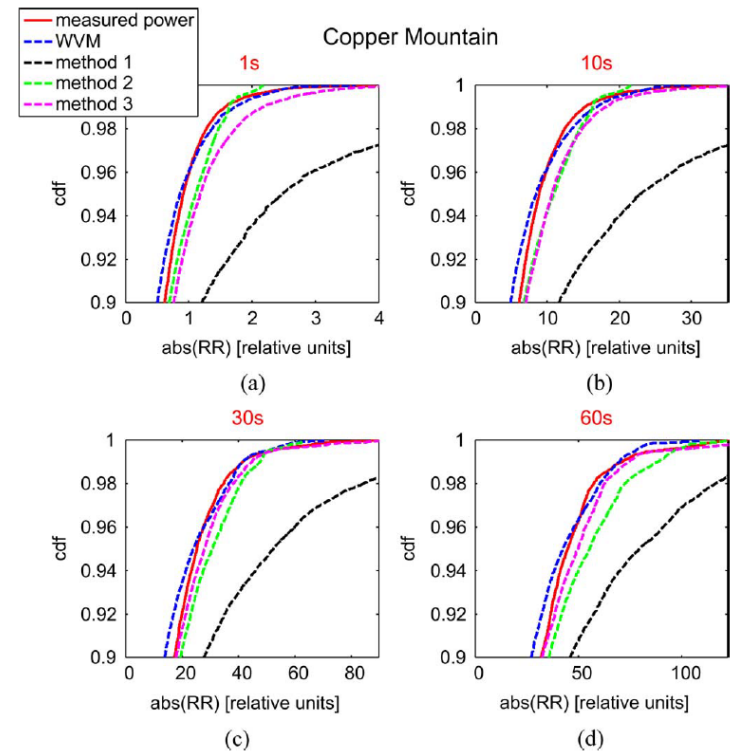

Fig. 9. Extreme (>90th percentile) ramp rate cumulative distribution functions at CM on October 1, 2011 at (a) 1 s, (b) 10 s, (c) 30 s, and (d) 1 min for measured power output (solid red), and for different methods of simulating PV power plant output: WVM (dashed blue), Method 1: linearly scaling from a point sensor (dashed black), Method 2: a moving average of 115 s corresponding to $t_{avg} = Ar^{1/2}/V$ (dashed green line), and Method 3: averaging all 15 reference cells (dashed magenta line).

Adapted from "A Wavelet-Based Variability Model (WVM for Solar PV Power Plants" by Matthew Lave, Jan Kleissl, and Joshua Stein, 2013, IEEE Transactions on Sustainable Energy, Volume 4, No. 2

Lave et al. Rolling Average

- $MovingAvg(t) = average\left(data\left[t - \left(\frac{T}{2} - 1\right) : t + \frac{T}{2}\right]\right)$, where T is the length in seconds of your rolling average interval.

  - Ex: A 2 minute rolling average has an interval size $T = 120s$, and
    $MovingAvg(t) = average(data[t - 59: t + 60])$

- Equation to translate from desired plant size to interval length $\longrightarrow$

- Algorithm to translate second-based calculation to minute-based calculation (see appendix)

Rolling Average Interval vs. Solar Farm Size
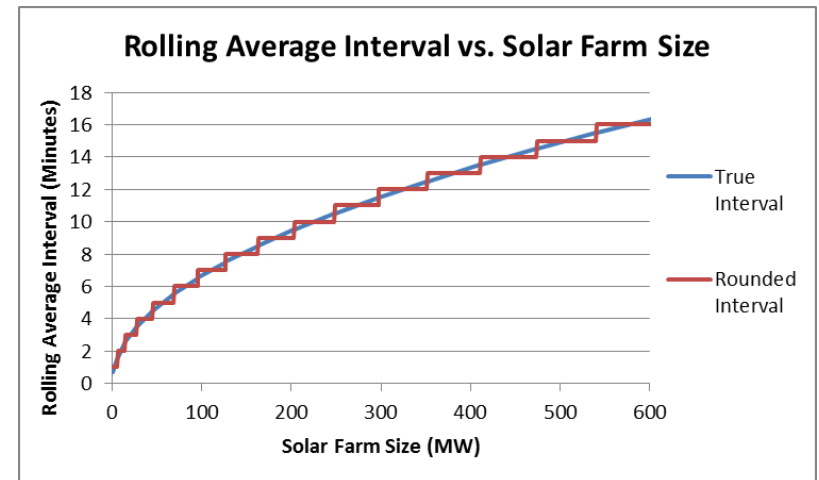
Scaling Comparison
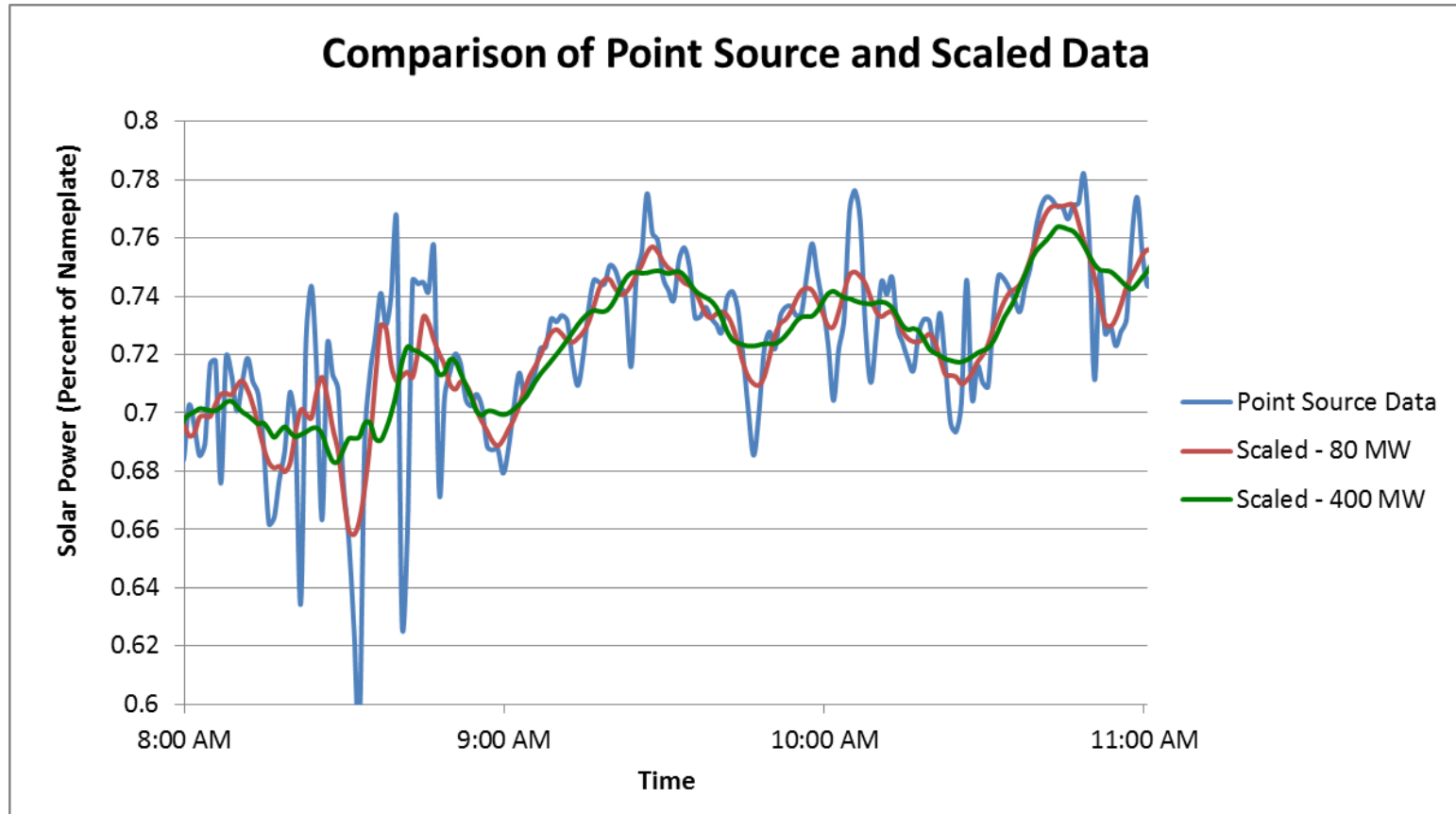
Appendix 3: Solar Scheduling Options and Calculations

Solar Scheduling Options and Calculations

- 30/15 Persistence
  - The measured generation output occurring 30 minutes prior to the 15-minute scheduling interval is used for the 15-minute schedule.
  - This scheduling paradigm produces an updated schedule every 15 minutes and can not be calculated ahead of real-time operations. This option produces the lowest station control error per plant.
- 30/60 Persistence
  - The measured generation output occurring 30 minutes prior to the 60-minute scheduling interval is used for the 60-minute schedule.
  - This scheduling paradigm produces an updated schedule every 60 minutes and can not be calculated ahead of real-time operations. This option produces more station control error per plant than 30/15 but less than Matrix.
- Matrix
  - For each combination of Month-of-Year and Hour-of-Day, an average of generation during all past instances in that Month and Hour is taken and used as the schedule for that Month/Hour combination.
  - For example, to produce the schedule value for hour ending 8 for the month of June, the average generation during HE8 in the month of June for all past years of data is averaged together. The resulting average will be the schedule for HE8 for each day of June in the target year.
  - This scheduling paradigm can produce a schedule for an entire year, resulting in a matrix of 12x24 values representing the averaged past data for each Month/Hour combination. This options produces the most station control error per plant.

30/15 Persistence Schedule Example

Rounded Average HE8 Generation Value for June