Factors and Options for Improved Frequency Regulation: Case Study of Utility Scale Solar in Nigeria

Barry G. Rawn[1], Tochi Nwachukwu[2], and Erkut Cebeci[3]

***Abstract*— This paper presents the structure, tuning, and evaluation of a model for power system frequency response in Nigeria. We demonstrate that a 100MW utility scale solar farm is unlikely to degrade frequency performance, and we quantify the effect of several possible interventions to improve frequency regulation. The Nigerian system already experiences wide frequency variations due to steel mill loads and load rejection during storms, and this often necessitates manual intervention and load management. The model is one of several employed in grid-integration evaluations of proposed large utility-scale solar farms. The model is intended to support ongoing discussions on how grid code and market policies should specify ancillary services supplied by participants.**

I. INTRODUCTION

Small power systems can experience excessive frequency variations, especially if they have large industrial loads. An understanding of how grid participants correct imbalance is crucial in such systems, especially when connection of renewable power generators is anticipated. When frequency is consistently off nominal, generating parties suffer due to degradation of their stations, and failures due to ancillary systems are more likely. Once several generators begin not to comply with requirements to provide frequency droop, the burden on other generators increases.

II. CURRENT FREQUENCY PERFORMANCE AND PRACTICE

The Nigerian peak load varies between 3.8 and 5.1 GW. Served by approximately 61 generating units at 25 power stations, the system typically has between 40 and 120 MW of reserve held by only 1-5 generating units. Such units usually are programmed with droops that presume active governors for all machines in the system (typically a value of 5%). Observed regulation characteristic as reported in this paper is approximately 200MW/Hz. Frequency tends to run high, so that generators on reserve back down to a mid-point and can use their full range of reserve for frequency response. Significant manual frequency balancing occurs, with several to dozens of raise and lower instructions issued by the operator each day. These actions tend to trigger when the frequency is excessively high or low. The resulting frequency variations can be seen in Fig. 1.

[1]Barry Rawn is with the College of Engineering, Design and Physical Sciences, Brunel University London, United Kingdom `barry.rawn at brunel.ac.uk`

[2]Tochi Nwachukwu is with the Nigeria Infrastructure Advisory Facility `tochi.nwachukwu at niafng.org`

[2]Erkut Cebeci is with EPRA Engineering Procurement Research Analysis `erkut.cebeci at epra.com.tr`

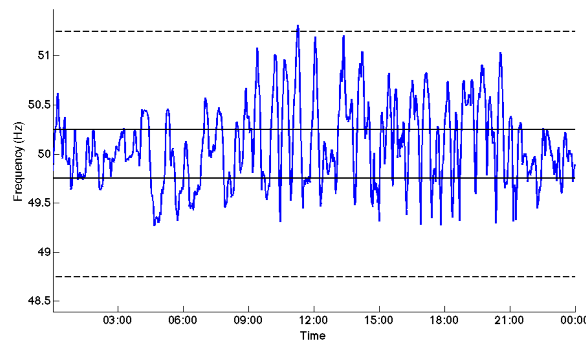


Fig. 1. Sample day of Nigerian frequency variations Solid and dashed horizontal lines mark grid-code specification for normal and stressed operation respectively.

III. MODEL OF NIGERIAN FREQUENCY RESPONSE

Three types of generator are found in Nigeria- hydro turbines, steam turbines and gas turbines. Gas turbines have been modeled as simple open-cycle GTs. The gas turbine governors are modeled to reflect efficiency losses that depend on system frequency. All governors are modeled, along with a single mass model of the power system, in MATLAB Simulink. Individual units are modeled and their outputs summed.

A. Model Calibration

A generation loss event of known magnitude can be used to estimate total system frequency response parameters. These parameters are a combination of generator parameters, which are known from commitment records, and load parameters, which must be estimated. Frequency recordings from a phasor measurement were available, as were system records listing the time and parameters of major events.

Based on elements of a daily report issued by the system operator, it was determined that a generation loss P_{loss} of 40MW occurred; a clear transient at the recorded point in time is indeed shown by the frequency record in Fig. 2.The estimated inertia constant

$$\hat{H}_{sys} = \frac{1}{2}\frac{P_{loss}/P_{base}}{d\Delta\omega/dt} \tag{1}$$

was found to be 7.5s. Subtracting a computed generator inertia constant from commitment records according to

$$H_{gen} = \frac{\mathbf{S_{gen}} \cdot \mathbf{H_{gen}}}{\sum_i S_{gen,i}} \tag{2}$$

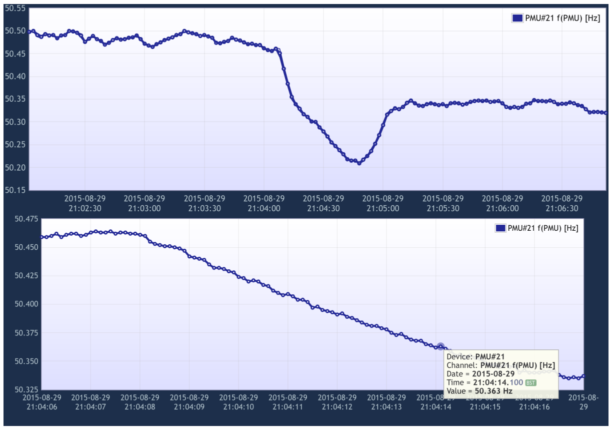


Fig. 2. Tripping of Oloronsogo Gas Turbine unit at 21:03 PM, loss of 40 MW. Initial rate of drop from 50.46 Hz is 0.1 Hz over 6 seconds, estimated final nadir (not reached due to additional event) 50.26 Hz.

implied a a load inertia constant

$$H_{load} = H_{sys} - H_{gen} \tag{3}$$

of 2.8s, a value similar to reported [3] load inertias as being 20-30% of generation inertia. The reserve records can provide the total rating S_{res} on units on the recommended droop D_{gen} in per-unit and hence the expected droop response from generators based on the observed speed change:

$$\Delta P_{droop} = \frac{\Delta\omega^{ini} - \Delta\omega^{fin}}{D_{gen}} S_{res} \tag{4}$$

which in turn allows determination of load damping percentage based on the load's apparent contribution to compensate the lost power

$$D_{load} = \frac{1}{\Delta\omega^{ini} - \Delta\omega^{fin}} \frac{P_{loss} - \Delta P_{droop}}{P_{load}} \tag{5}$$

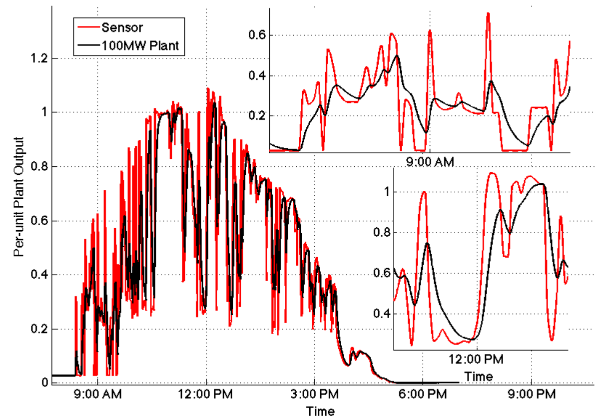
as 1.5%, which is approximately in the middle of typical values [1].

IV. Model of Net Load

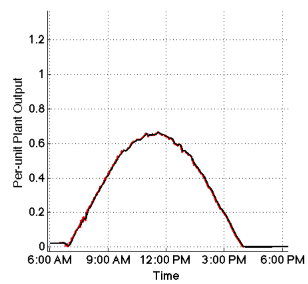
The calibrated model established can be simulated to infer load variations based on some simplifying assumptions and the following rearrangement of the rotor speed equation, which is driven by a frequency measurement $\Delta f(t)$

$$\Delta P_{load} = -\,2H_{sys}\frac{d\Delta f/f_{nom}}{dt} \tag{6}$$
$$-\,D_{load}\left(f/f_{nom}\right) \tag{7}$$
$$+\,\Delta P_{gen}\left(\Delta f/f_{nom}\right). \tag{8}$$

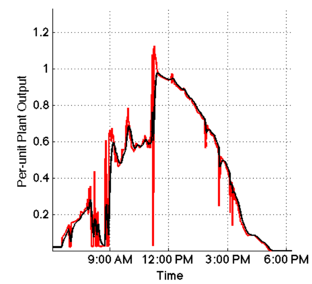
and sums inertial, load response, and governor response terms to infer load variations. It has been assumed UFLS settings of relays in the system were not triggered on the day in question. Reverse time simulation would yield a more accurate result, but the relation (8) was judged as sufficient to at least estimate the proportional component of generator response $P_{gen}(\Delta\omega)$.



(a) Partly Cloudy, Nov 9th 2004



(b) Overcast, Nov 1st 2004



(c) Light Cloud, Nov 26th 2004

Fig. 3. 1-min irradiance sensor data (red) at Ilorin and estimated smoothed farm output (black). Top inset of partly cloudy case shows effect of filter for one hour centered on 9 AM, bottom inset shows 40 minutes centered on 12 PM.

Achieving an acceptable balance between generation and demand requires understanding of the most significant disturbances to each category. System operators believe that electric arc furnaces contribute the largest component to load ramping, while the largest sudden event tends to be a generation surplus due to rain storm induced load curtailment across large urban distribution systems. The introduction of solar increases the former category of net-load variations, and these are thus examined further.

A. Electric Arc Furnace Load

The total possible amount of arc furnace load is estimated at 317 MW, based on the 22 known installations. The expected variations could in theory range from an unlucky 310 MW change all at once, to the uncorrelated case where adding arc furnace ratings in quadrature gives a possible ramp rate of 135 MW Power draws of two arc furnaces as measured from transformer measurements were used as a basis for synthesizing a worst case time series that approximates the variation of the Nigerian fleet of arc furnaces, which can be assumed to operate independently of each other. Scaled and randomly shifted copies of the arc furnace measurements were summed and combined to make a load variation timeseries, which was then evaluated in terms of 10 and 1 minute changes, along with the inferred

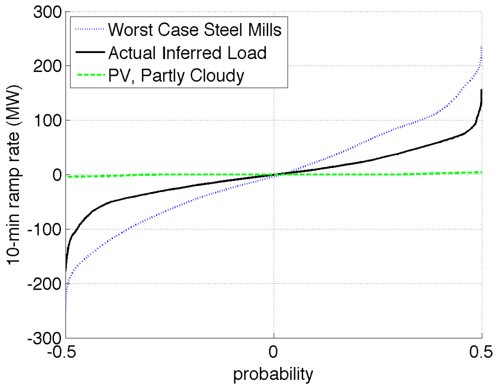


Fig. 4. Ramp rates of inferred load compared against worst-case arc furnace and utility-scale solar plant.

load and solar net load, as described in Section IV-C.

B. Solar

Irradiance time series measured at Ilorin at 1 min intervals through the Base Station Radiation Network have been filtered to generate estimated electricity production variations at a 100MW utility scale solar farm. Data from November of 2014 were selected based on data availability and occurrence of high variability to provide a worst case. Based on information about cloud ceiling for the days in the studied month of data, a filter time constant [2] was computed

$$\tau = \sqrt{A}\left(v_{mast}\left(\frac{h_{cld}}{h_{mast}}\right)^{0.14}\right)^{-1} \tag{9}$$

where A denotes the solar farm area, chosen as 3 km^2 based a land use factor of 7.2 $MW/acre$ published for utility scale photovoltaic plants [4] and where the denominator is an estimated cloud speed extrapolated using a logarithmic shear law. Fig. 3 shows the expected power production.

C. Ramping Evaluation

The ramp rates at 10 minute and 1 minute intervals can be used to evaluating the need for ramping reserves and regulating reserves respectively. In this case, a worst case day has been chosen as an indication; a study of a whole year or would normally used to recommend reserve levels based on risk. A comparison in Fig. 4 of the worst-case synthesis of potential ramp rates from electric arc furnaces against inferred load shows that it strongly overestimates possible load variations, with the synthetic estimate having a pessimistic distribution and maximum ramp value. The implication of this is that while the inferred load does likely exhibit some arc furnace component, and has ramp rates large enough to be explained by such installations, it does not approach the worst case variation that might be expected even from uncorrelated simultaneous arc furnace operation.

On the other hand, the distribution of the worst-case solar injection (from a partly cloudy day) proves to be relatively small compared to the inferred load, meriting more close

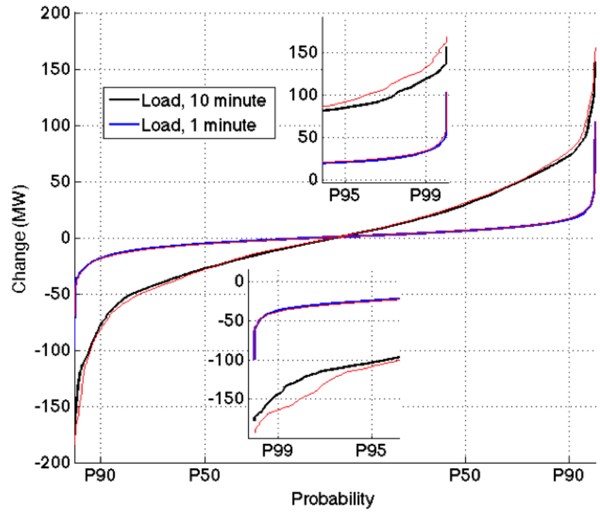


Fig. 5. Summary of load variations; insets show distribution tails. Thin red line indicates net-load for partly-cloudy utility scale farm.

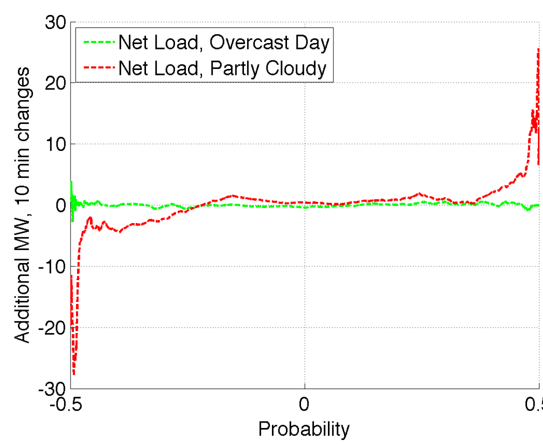
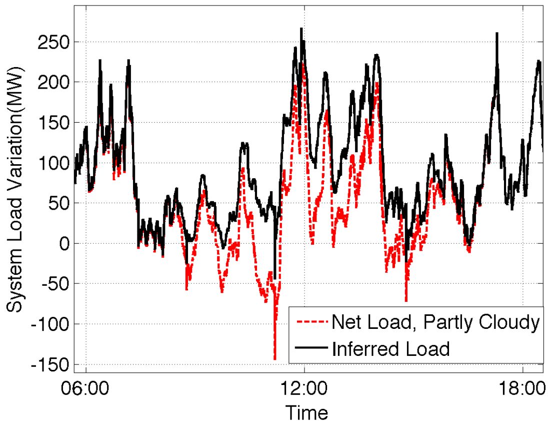


Fig. 6. Additional ten-minute variations to be covered by reserves.

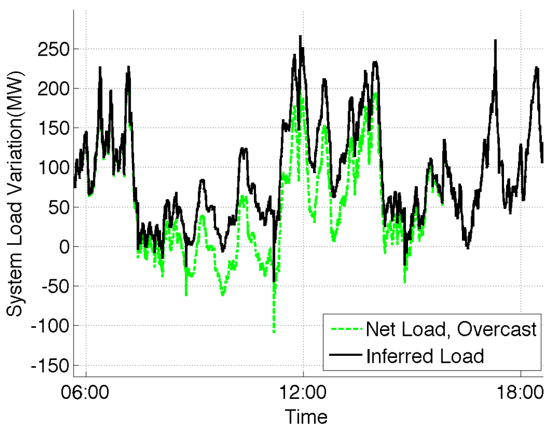
comparison. A summary of probability values for different ramp rates is summarized in Fig. 5.The total effect on load variations is relatively small.

The difference between the ramp distribution of the inferred load on its own has been compared with that of the the net load of inferred load minus solar in Fig. 6. The most extreme positive and negative 10-minute ramps are larger than the inferred load variations by 20 MW respectively. Typical reserve levels kept vary widely, and are sometimes adequate. The analysis of the one day's data as summarised in Fig . 8 suggests that carrying up to 100MW of reserve would cover all but the worst 5% of ten-minute changes.

When overcast and partly cloudy cases for the prospective utility-scale solar farm are added to the inferred load, the resulting net-load is depressed during the solar day as seen in Fig. 7



(a) Partly cloudy case



(b) Overcast day

Fig. 7. Net load variations over daylight hours compared against inferred load variation.

V. Evaluation of Frequency Improvement Measures

A number of measures are under consideration to improve frequency regulation in Nigeria. A key problem is the lack of a financial incentive to deliver ancillary services. In this paper, we study only the technical issues associated with potential delivery of these services. Having reproduced the generator settings and inferred load that are as realistic as possible in the scope of this study, we can visit several types of frequency control remedies to compare their effects.

A. Under and Over-frequency Response

To avoid damage and excessive operator instructions due to prolonged operation at high or low frequency, high frequency response from generators could be required of utility scale solar farms. Fig. 8 provides information about the fraction of time that operation above or below a certain threshold can be expected. This provides an indication of solar energy curtailment necessary to provide an automatic replacement for emergency dispatches normally issued by operators to combat overfrequency.

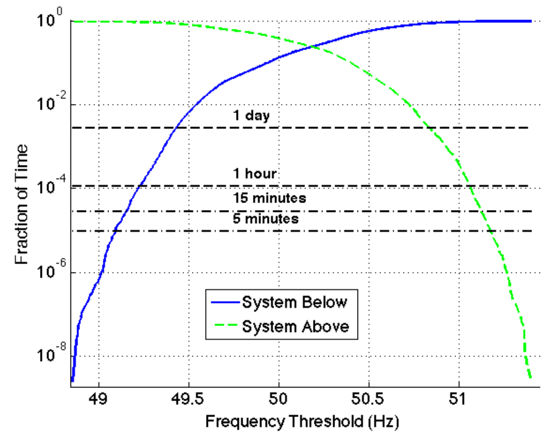


Fig. 8. Frequency distribution of 6 months of daylight hours of 1 minute data: cummulative time spent under (solid) and over (dashed) a given frequency.

To take a specific example, one day has been studied with an additional control look that provides one-sided frequency response, with a deadband set to only react to frequencies above 51 Hz. This effectively curtails the utility scale solar farm's production in stressed conditions. The effect during daylight hours is shown in Fig. 9. The quantity of withdrawn power, ranging from 20-64 MW, keeps system frequency below the threshold of stressed operation (dashed line) as defined by grid code. In the worst case, for a fully sunny day of production that might produce 600 MWh, the curtailed solar power could be as high as 49 MWh, or 8%. Using Fig. 8 to assess the amount of time spent above 51 Hz based on 6 months of data, it appears that period of time involved in curtailment may be more like 0.04% of the time, or 3.5 hours per year, a more reasonable figure for project developers.

Neither solar power curtailment nor the existing UFLS system are certain solutions to the problem of frequency excursions. Solar plants are available to back off generation under high frequency only during daylight hours, and may be limited in the total MW change due to weather conditions. Load shedding schemes do not have any control of the amount of load presently connected to a feeder downstream, and so may not necessarily deliver the MW change expected.

B. Unit Commitment for Inertia, Droop Adjustments

Committing more units and providing them headroom with governors activated is a clear solution to the frequency regulation problem. Some factors to consider are:

- full commitment of all units to provide inertia
- activation of droop response on all generators
- load reduction to match commitment.

An increase from 7.6 s to 10 s of inertial energy (calculated using peak load as a base, rather than generation rating) can be achieved by committing all units. However, simulations have indicated that this produces only a modest smoothing of frequency patterns.

The most straightforward approach is to activate governors on all generators. The effect of this is shown in Fig. 10.

Respecting a 5% droop tolerance and de-loading for appropriate headroom brings frequency within the normal ranges specified by the Transmission Company of Nigeria. These ranges are marked in the time series displayed in Fig. 11. Fig. 11 also demonstrates that without some reduction of overall load by at least 5%, the saturation of governor response leads to precipitous drops in frequency, significantly in excess of the even the base case variations.

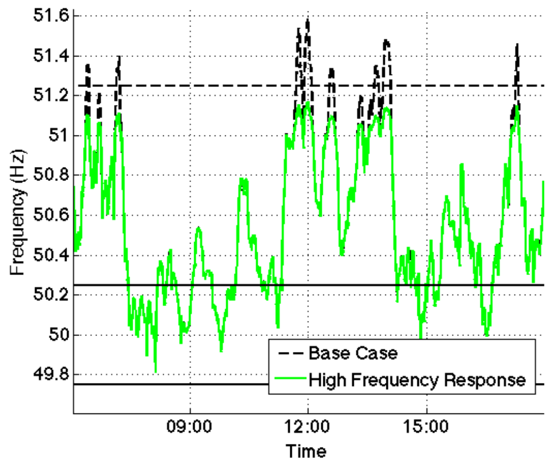


Fig. 9. Frequency time series showing high frequency response from solar. Solid and dashed horizontal lines mark grid-code specification for normal and stressed operation respectively.

VI. Conclusions and Future Work

Active power variations from a utility-scale solar plant were found to cause only modest increases in the ramp-rates of net-load in Nigeria, based on an inferred load variation pattern derived from frequency measurements and a calibrated frequency response model. More frequency data are available and could support a more robust analysis, but the authors believe the use of the most variable possible solar input provides a conservative confirmation that utility-scale solar does not pose a threat to frequency regulation in Nigeria. A comparison of an inferred load with a synthetic arc furnace record confirmed that uncorrelated arc furnace activity could be an explanation for the relatively large load variations implied by the frequency record, as the peak values observed are comparable.

A better calibration model using a regression against multiple events available from the frequency and system records would improve the confidence that the model is appropriate and also reveal information about the change of load characteristics. The challenging aspect of operator actions present in the power imbalance signal can be dealt with by a more exhaustive study of system reports and possibly a model of operator actions, either ARMA or Markov. To support discussions on measures introduced through regulatory order, a higher fidelity to the special circumstances prevailing in Nigeria could be obtained by taking account of current under-frequency load shedding behaviour and of operator instructions and responses.

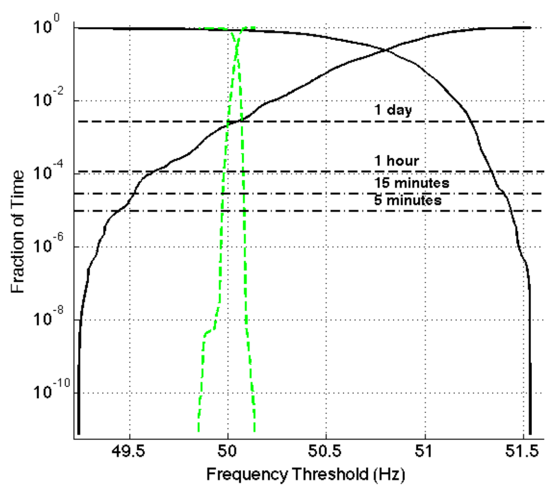


Fig. 10. Frequency distribution of the chosen day of 1 s data, with under/over curves for two cases: current droop settings (solid) and 5% droop obeyed by all generators, with deloading to 0.95 (dashed).

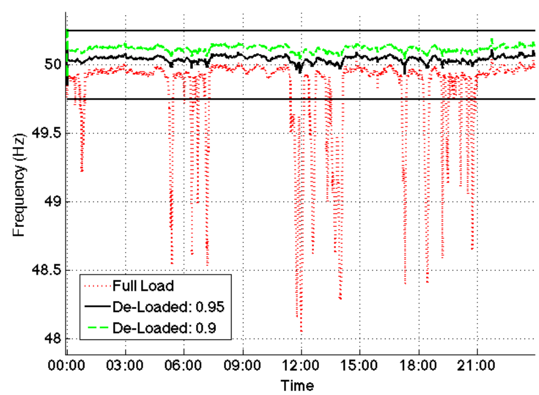


Fig. 11. Frequency time series for one day of collective droop control; reducing overall load better centers the setpoint of committed generators to preserve headroom.

Acknowledgment

Authors thank the World Radiation Monitoring Center for granting access to irradiance data from the Baseline Surface Radiation Network, and Studio Elektronika Rijeka, for its provision of a phasor measurement unit.

References

[1] P. Kundur. *Power system stability and control*. McGraw-Hill, Inc., 1994.

[2] A Longhetto, G Elisei, and C Giraud. Effect of correlations in time and spatial extent on performance of very large solar conversion systems. *Solar energy*, 43(2):77–84, 1989.

[3] MO Malley and Gill Lalor. Ancillary services markets and wind power, 2002.

[4] Sean Ong, Clinton Campbell, Paul Denholm, Robert Margolis, and Garvin Heath. Land-use requirements for solar power plants in the united states. *Golden, CO: National Renewable Energy Laboratory*, 2013.