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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO ESTABLISH NEW SCHEDULES FOR RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS WITH ON-SITE GENERATION	))))))	CASE NO. IPC-E-17-13

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DAVID M. ANGELL

Q. Please state your name and business address.

A. My name is Dave Angell. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Transmission and Distribution Planning Manager.

Q. Please describe your educational background.

A. I graduated in 1984 and 1986 from the University of Idaho, Moscow, Idaho, receiving a Bachelor of Science Degree and Master of Engineering Degree in Electrical Engineering, respectively. I have provided electrical engineering instruction for both the University of Idaho and Boise State University. Most recently I instructed power system analysis at Boise State University during the 2009 spring semester. I am a licensed professional engineer in the State of Idaho and a senior member of the Institute of Electrical and Electronic Engineers.

Q. Please describe your work experience with Idaho Power.

A. From 1986 to 1996, I was employed by Idaho Power as an engineer in both communications and protection systems. In 1996, I became the Engineering Leader of System Protection and Communications. I held this position until 2004, when I transferred to Transmission and Distribution Planning. During the fall of 2006, I accepted the positions of System Planning Leader and Manager of Delivery Planning. I have been managing Idaho Power's interconnected-transmission system, sub-transmission, and distribution planning since 2006.

Q. What is the purpose of your testimony in this proceeding?

A. I will provide an explanation of the electrical grid and how the Company's residential and small general service ("R&SGS") customers with on-site generation utilize the distribution system. I will then address the question of whether increasing levels of distributed energy resources ("DER") will contribute to the deferral of future investment in distribution infrastructure. Finally, I will describe how smart inverters provide functionality that is necessary to support the ongoing stability and reliability of the distribution system and explain the Company's request relative to a smart inverter requirement in Schedule 72 for customers who interconnect privately-owned DER to Idaho Power's system.

I. <u>THE GRID</u>

Q. What is meant by the term "the grid"?

A. The grid, in this context, is the electric power system including the conversion, transformation, transmission, distribution, and delivery of energy in the form of electricity to customers.

The conversion of energy contained in reservoirs, fossil fuels, wind, geothermal wells, or solar rays to electricity power occurs at generation stations. Many of the generation stations are located remote from the customers' point of use. Therefore, the electricity is transformed to extremely high voltages in order to reduce the electrical losses when transmitting the electricity on transmission lines for long distances. Transformers are used throughout the grid to change the electric voltage level to match utilization and reduce electric losses. Once the electricity is delivered to communities, it is transformed to a lower voltage at substations for local distribution. The electricity is distributed through the local community on distribution lines where transformers are used to tap the line and deliver customers electricity at a reduced voltage to match their intended use.

Q. What kinds of services does the grid offer Idaho Power customers?

A. The grid offers reliable electricity delivery, in the context of dependability and balance of supply, across large regions in the amount and at the instant of customers' demand. The grid also provides flexibility by allowing the utility access to a diverse portfolio of resources for power generation, even if those resources are located far from where the power is needed.

Q. What functions does Idaho Power perform in order to maintain a safe and reliable distribution system and grid?

A. In order to provide safe and reliable energy on demand, Idaho Power must perform the following functions: voltage control, system protection, scheduling, dispatching, and load balancing. These functions are commonly referred to and collectively known as ancillary services.

Q. How does Idaho Power control voltage to maintain a safe and reliable distribution system and grid?

A. Voltage control is achieved by managing the voltage throughout the grid at the generator, transmission, and distribution systems. Automatic voltage regulating devices control the voltage output of the generators to match the grid operators set voltage. At the substations, grid operators also remotely switch substation capacitors and inductors to raise and lower the transmission voltage, respectively. Automatic voltage management occurs at the distribution substation transformers with voltage control based on load, known as load tap changers. Additional automatic control signals are sent to switched distribution circuit capacitors based on substation transformer loading.

Finally, voltage control occurs at substations that service large commercial and industrial customers.

Q. What is system protection?

A. System protection is the detection and isolation of both short circuits and system operation that may damage generation, transmission, substation, and distribution facilities. Idaho Power coordinates the protection equipment to isolate only the failed component and allow the remaining grid to continue to supply energy.

Q. How do scheduling, dispatching, and load balancing help Idaho Power maintain a safe and reliable distribution system and grid?

A. The Idaho Power-owned generation stations are controlled by grid operations personnel. These personnel schedule a generator's electrical output ahead of time based on the load forecast and its optimal use in consideration of energy market economics. During each hour of the day, the operators efficiently dispatch the generation fleet to maintain the balance between production and forecasted use. They operate the generation stations within a set of operational, environmental, and economic constraints to maximize customer value. Some of these generation stations are also configured with the nearly instantaneous ability to automatically adjust the electric output to balance the generated electricity with the actual use, known as automatic generation control. Additional generation capability is held in reserve and is available for dispatch if the actual load exceeds the forecast or if some of the dispatched generation is forced out of service unexpectedly.

Q. How do wind and solar resources impact this scheduling, dispatching, and load balancing?

A. Independently-owned wind and solar generation resources differ from Idaho Power-owned and operated generation stations because their production is difficult to forecast and they cannot be dispatched by Idaho Power's grid operators. Because the actual output from these independently-owned resources typically varies from the forecast, they place increased demands on the dispatch and utilization of the automatic generation control and reserve generation.

Q. Does DER located on the customer side of the meter increase the complexity of forecasting?

A. Yes. While on an individual basis a small independently-owned on-site generation system (capacity of < 25 kilowatts ("kW")) may not be noticeable to the automatic generation control, the aggregate amount of DER installed across Idaho Power's system is noticeable and does increase the complexity of forecasting. As of June 30, 2017, Idaho Power's net metering service had a cumulative nameplate capacity of 11 megawatts including customers who had submitted applications for net metering service. Because the net metered systems are installed on the customer side of the meter, Idaho Power is not able to detect the amount of DER at any given moment, which increases complexity of both forecasting and load following.

Q. You have described the overall services that the grid provides to Idaho Power's customers and the functions that Idaho Power performs to maintain a reliable grid. Does the grid provide other services that are specific to a person with privately-owned generation?

A. Yes. The grid provides the following services that customers with privately-owned generation require: inverter operation, motor starting, energy balancing, and standby service.

Q. What is an inverter?

A. Inverters convert direct current ("DC") electricity into alternating current ("AC") electricity. Inverters are used in both off-grid and on-grid applications. An inverter is required for customers who install a photovoltaic ("PV") generation system because solar panels produce DC electricity and the home appliances require AC power supplied by the inverter.

Q. What is the difference between an "off-grid" application and an "on-grid" application?

A. An off-grid generation system is one that is not interconnected to the electric grid; the off-grid system provides all electric needs of the owner -- they are independent of the utility. In the case of an off-grid solar PV system, the DC electricity generated by the PV system is used to charge a battery bank connected to the customer's equipment through an off-grid inverter, which does not require the grid to operate.

On the other hand, an on-grid generation system is one that is interconnected to the electric grid. For on-grid systems, the DC electricity generated by the PV system is sent directly to an on-grid inverter which converts the electricity to AC for use by the DER customer or other customers through the grid.

Q. How does the grid provide services for on-grid system inverter operation?

A. Without the grid, the customer's generation system would not operate because these line commutating inverters would not be able to develop voltage or deliver energy. In other words, the grid must be present for customers with on-grid inverters to operate their generation system.

For the remainder of my testimony, all discussions in regard to inverters will be specific to on-grid inverters.

Q. How does the grid enable a customer with self-generation to start a motor?

A. Electro-mechanical devices such as generators and motors transfer energy via the interaction of magnetic fields. These magnetic fields require current in addition to the current associated with the energy transfer. This additional current is known as reactive current. The induction motor, the most widely used motor, is constructed with an electro-magnet which relies on a power source to develop a magnetic field. When energized, the motor has no magnetic field to impede the current flow from the power source. Therefore, during motor starting, a current draw of about six times the full load value occurs. Most inverters currently interconnected with the Idaho Power system are not able to supply these high starting and continuous reactive currents. The grid, via its generators and capacitors, supplies the motor starting and continuous reactive current. In other words, a customer with on-site generation would not be able to turn on certain equipment like air conditioners, pumps, and household motors without being connected to the grid.

Q. How is standby service provided by the grid beneficial to a customer with self-generation?

A. When a customer's self-generation system is not able to meet their demand, that customer must rely on power from the grid. Also, when a customer's system is not generating because of weather conditions, time of day or operational malfunction, the customer relies on power from the grid to meet their electricity demands.

Q. Is it a requirement for someone with privately-owned generation to be connected to the grid?

A. No. A person with privately-owned generation is not required to be connected to the grid. However, most customers voluntarily choose to connect to the grid in order to receive the services that the grid provides as described above.

II. USE OF THE GRID BY STANDARD SERVICE CUSTOMERS AND CUSTOMERS WITH ON-SITE GENERATION

Q. How do R&SGS customers with on-site generation use the grid compared to R&SGS standard service customers?

A. The primary difference is that the R&SGS customer with on-site generation uses the grid in a bi-directional manner by both consuming energy from the grid and delivering excess net energy to the grid when not consuming all generation on-site. The standard service residential customer only consumes energy from the grid.

Furthermore, while the daily demand requirements of the two customers may be similar, the net monthly energy may not reflect the utilization of the grid by the on-site generation customer.

Q. What is meant by the term "net zero" customer?

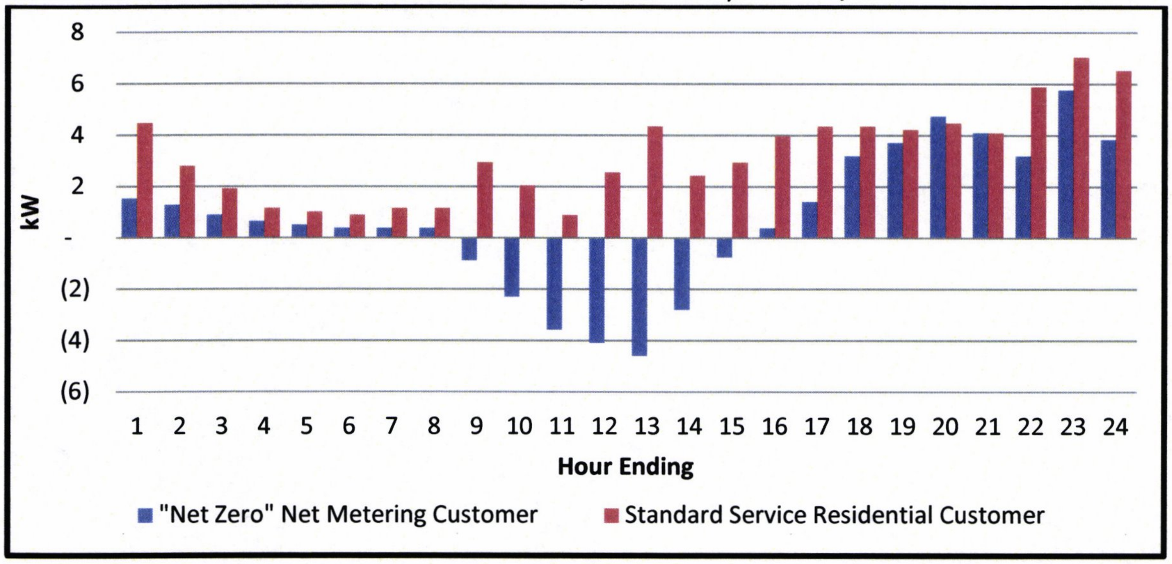
A. A net zero customer is one that, over the course of a year, generates as much or more energy (kilowatt-hours ("kWh")) than they consume. That is, during certain hours of the year, the customer is a net exporter of energy to the grid, and during other hours of the year, the customer is a net consumer of energy from the grid.

Q. Does the net zero customer utilize the distribution system less than the standard service residential customer?

A. No. A net zero customer utilizes all aspects of Idaho Power's grid during the hours they are consuming energy (including the generation, transmission, and distribution systems) and utilizes the distribution system during the hours they are exporting energy to the grid.

To illustrate this, the Company selected a single residential net metering customer who netted their usage to zero during 2016. Figure 1 demonstrates the hourly usage of that residential net zero net metering customer on the Company's 2016 adjusted system peak day (June 29) and compares that customer's hourly usage to a standard service customer's usage whose home is nearby the net metering customer.

Figure 1. Residential Net Metering Customer vs. Standard Service Residential Customer (June 29, 2016)



Q. Would you characterize these customers' usage as similar?

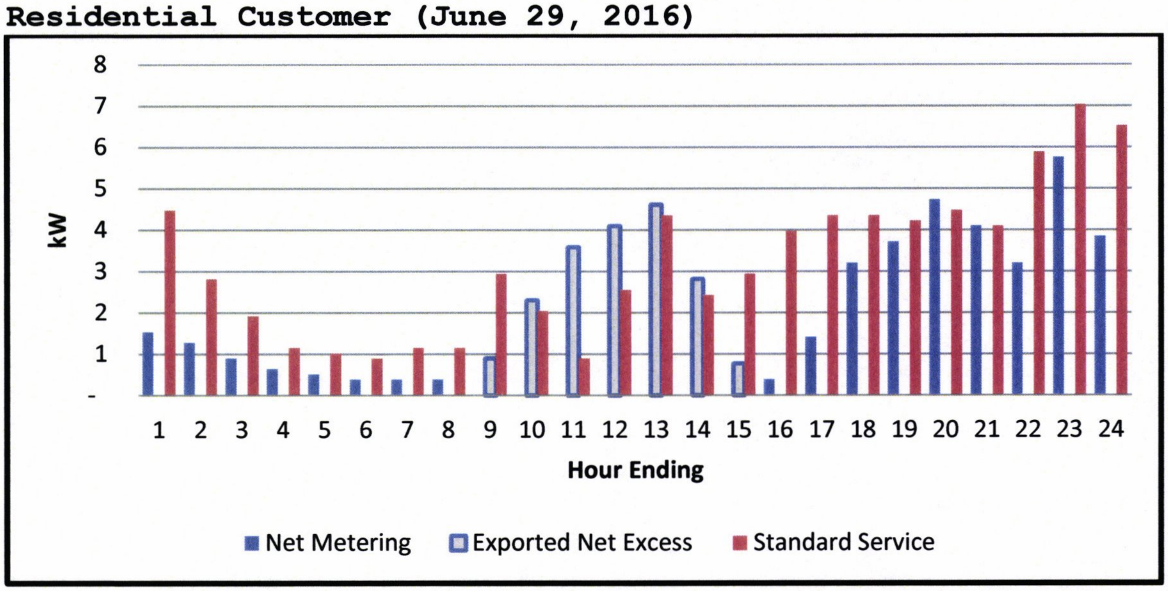
A. No. While the daily absolute demand requirements of the two customers are similar, the net monthly energy consumed by the net metering customer is not representative of their usage of the grid.

Q. Why is the net monthly energy not representative of the customer's use of the grid?

A. When a net metering customer exports excess net energy to the grid, their retail meter "spins backwards," or in the case of a modern meter, subtracts usage electronically. Later, during other hours of the day or month when the customer is consuming energy from the grid, the meter "spins forward," and adds usage electronically. On a monthly basis, the net metering customer is using the grid, every hour, every day, but because usage is measured for billing purposes on a monthly basis, that net metering customer appears to have "zero usage" for the month.

To understand the extent to which the net metering customer uses the grid, you can use the absolute value of the energy being transacted to and from the net metering customer. Figure 2 represents the same day as Figure 1, but shows all of the energy as positive, that is, the total amount of energy that is being transacted between the net metering customer and the Company's grid regardless of which direction the energy is flowing.

Figure 2. Utilization of the Distribution System by Residential Net Metering Customer vs. Standard Service Residential Customer (June 29, 2016)



The sum of the hourly consumed energy for the standard service residential customer on June 29, 2016, was 77.7 kWh, and the sum of the absolute value of the net hourly energy for the residential net metering customer was 55.4 kWh. Yet, when looking at their meter reads from that day, it would appear the standard service residential customer transacted 77.7 kWh of energy, while the residential net metering customer's meter would register that customer transacted 17.28 kWh.

When looking at the sum of all of the individual hours within the month of June for those same two customers, the sum of the hourly consumed energy for the standard service residential customer was 1,480 kWh, and the sum of the absolute value of the net hourly energy for the residential net metering customer was 1,323 kWh. Yet, when looking at their meter reads for the month, it would appear the standard service residential customer transacted 1,480 kWh of energy, while the residential net metering customer's meter would register that customer exported excess net energy of 440 kWh, to be carried forward to offset consumption in a future month, and that customer would be billed for zero kWh.

This demonstrates how the net monthly energy as a basis for billing does not reflect a net metering customer's utilization of the grid

III. **LOCAL DISTRIBUTION INVESTMENT**

Q. Has Idaho Power studied the relationship between distributed, rooftop solar PV and its distribution system operations?

A. Yes. In 2015, the Company performed a study comparing solar intensity variations and distribution circuit demand. This study is attached as Exhibit No. 14. A portion of the study sought to determine if there was a relationship between solar intensity and distribution circuit loading. The Company's system peak load is largely driven by the Treasure Valley residential and commercial loads. Therefore, weather stations with irradiance sensors were installed on a Treasure Valley distribution circuit that supplied primarily residential and some commercial customers. Three irradiance sensor orientations at three locations were used. The orientations were southerly facing at a 35° tilt, horizontal and westerly facing at a 53° tilt. The study demonstrated that there was a significant time delay between peak solar intensity and peak distribution circuit demand.

Q. What did the study conclude?

A. The study demonstrated that a southerly facing sensor peaked approximately four hours prior to the distribution circuit peak load and a westerly facing sensor peaked approximately two hours prior to the distribution circuit peak load. In both cases, similarly oriented PV systems will not significantly reduce a distribution circuit peak load. Additionally, the measurements demonstrate that the western facing PV system will create a steep decline in production at the end of the day that will result in a rapid change in circuit voltage and require enhanced voltage regulating abilities to respond to this rapid decline.

As the study concluded, even a system oriented west will not peak during peak load hours of the summer peak on a specific distribution circuit or substation. The distribution circuit peak load occurred from 17:00 through 19:00 hours. At 19:00 hours, the contribution from a PV array will be about 20 percent if faced southerly and about 55 percent if faced westerly. PV generation would only shift the peak load to 20:00 hours and decrease it by 10 percent. To illustrate this, Figure 3 presents a typical nominalized[1] load shape with the irradiance shape for the southerly-configured sensor and the resulting load shape less the solar irradiance.

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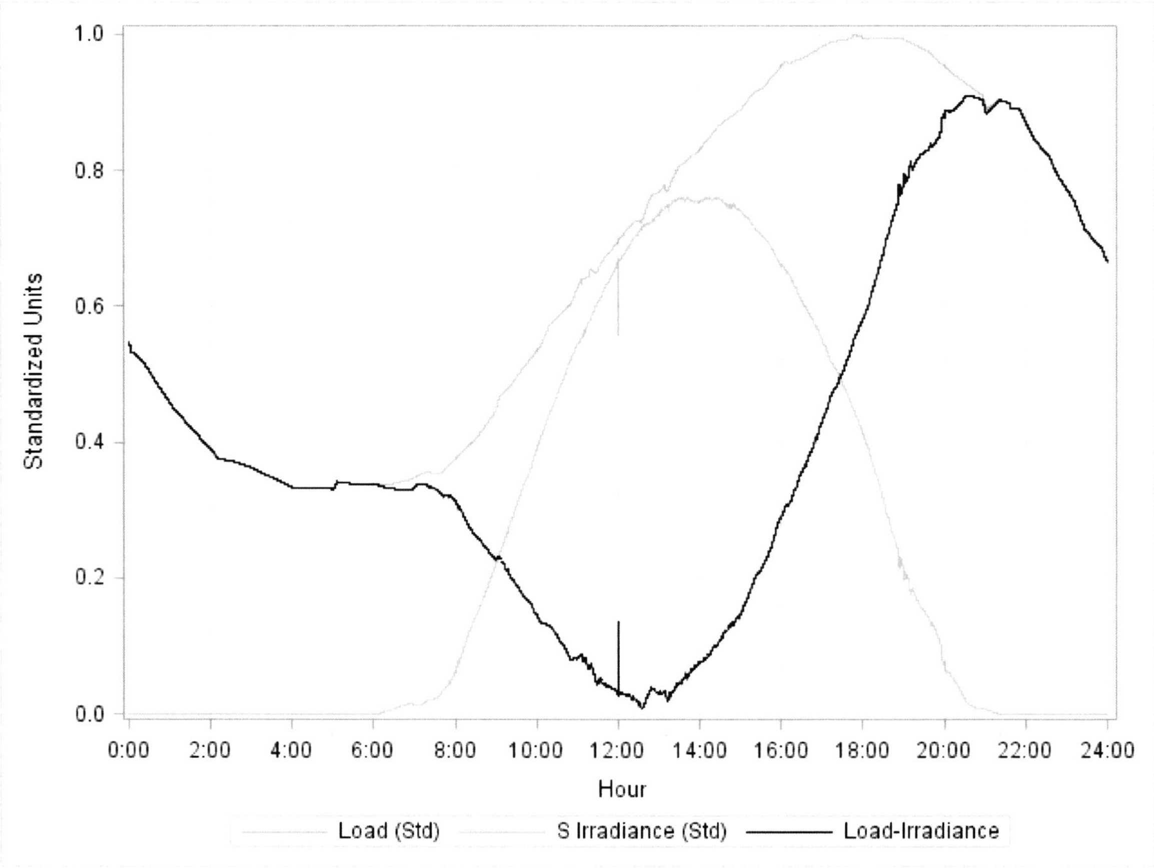
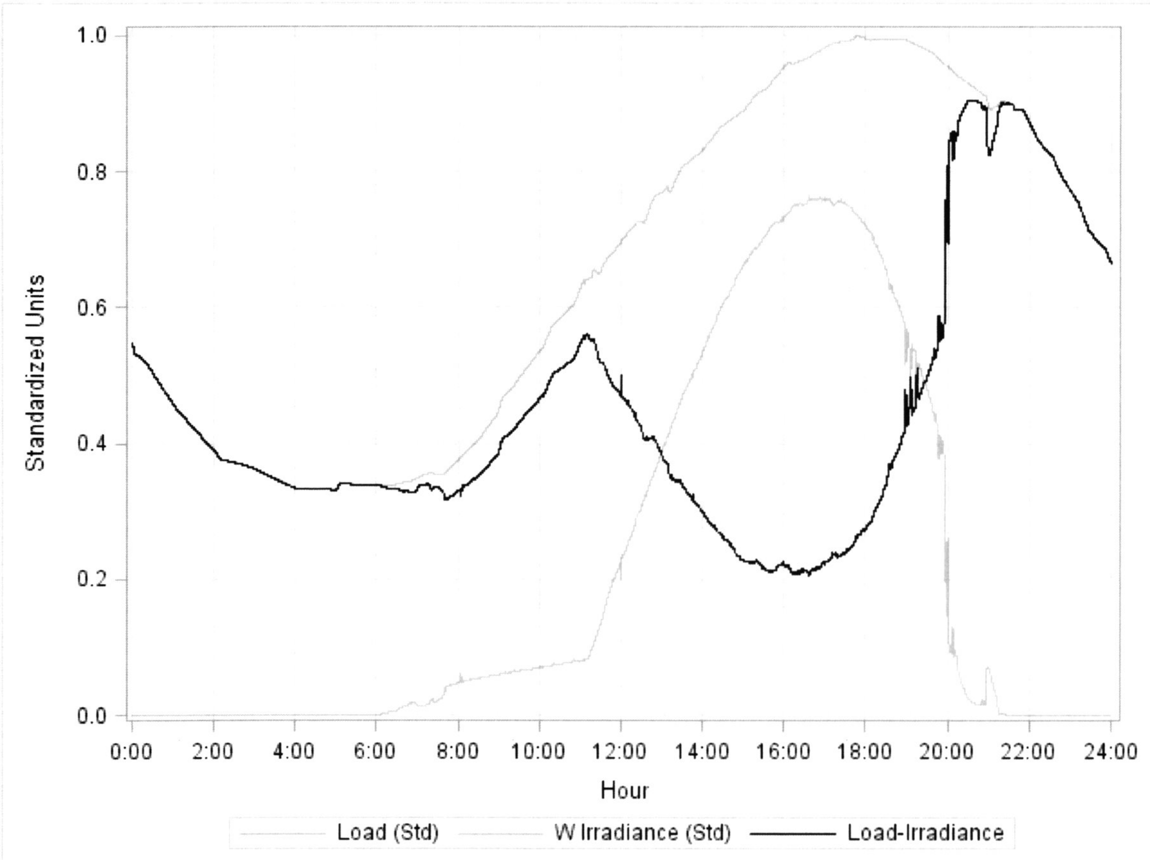
[1] To find relationships between solar intensity and load, the data was nominalized so that each variable ranged between 1 and 0. That allowed the two correlated time-series to be more easily relatable when graphed.

Figure 3. Southerly Solar Irradiance Shape vs. Load Shape



Similarly, Figure 4 presents a typical nominalized load shape with the irradiance shape for the westerly-configured sensor and the resulting load shape less the solar irradiance.

Figure 4. Westerly Solar Irradiance Shape vs. Load Shape



Q. Why is the planning horizon five years?

A. Idaho Power is able to forecast distribution circuit and substation capacity requirements with some certainty five years into the future. This planning horizon period allows the Company to investigate options to avoid facility overloads, select more cost-effective options, and design and construct improvements to meet the identified overloads.

Q. Can Idaho Power forecast on-site generation installations by distribution circuit and substation?

A. No. A customer's interest and ability to invest in an on-site generation system is based on many factors such as their ability to finance a system, risk tolerance, the local economy, and electricity prices. The last two factors are incorporated into the forecasts used in the Integrated Resource Plan analysis for on-site generation additions for the service area. However, it is extremely difficult to build a reasonable forecast with those same assumptions for specific circuits and substations.

Q. Can increased levels of rooftop PV reduce local distribution infrastructure investment?

A. Only in limited circumstances. Idaho Power has infrastructure in place to serve all customers during peak load hours. Idaho Power must plan and undertake distribution system investments in order to provide this reliable service. In order to reduce the infrastructure investment, sufficient PV additions must occur on the distribution circuit during Idaho Power's five-year planning horizon.

Q. Can you provide an example where infrastructure might be reduced?

A. An example of a circumstance where an investment could be deferred is a remote section of a distribution circuit where the load peak occurs during daylight hours, customers are increasing at a slow rate, and the voltage is declining. A traditional solution, e.g., installation of a capacitor, might be reduced by 20 to 50 kW of PV generation.

Q. Has this occurred on the Idaho Power system?

A. Yes. Idaho Power engineers reviewed the distribution system and found one location that met the criteria above. A pilot PV project was installed in 2016 and the engineers are presently monitoring the performance for evaluation this fall.

Q. Is the distribution system capable of handling increasing levels of DER without any modification?

A. No. High DER penetration amounts create distribution circuit operation challenges, such as voltage management, short circuit detection, and islanding. Islanding occurs when a customer's generation is capable of supporting the load of other customers physically located near the customer's generator when that section of the electrical circuit is isolated from the Idaho Power system.

Q. Why does the presence of DER impact the distribution circuit voltage?

A. When DER is contributing power to the circuit, it changes the power requirement from the distribution substation transformer as shown previously. This change in power flow causes the typical circuit voltage drop to change.

Q. What is meant by typical circuit voltage drop?

A. Voltage drop (loss) occurs any time power flows through a conductor. For a typical circuit, the voltage is highest at the substation (the power source) and drops to the lowest point at the end of the circuit. The rate of drop is based on the amount of current flow and conductor resistance.

Q. How is the distribution circuit voltage managed?

A. The distribution circuit voltage is typically automatically controlled by three components: (1) the substation distribution transformer load tap changer ("LTC"), (2) regulators located along the circuit, and (3) shunt connected capacitors. The LTC automatically adjusts the substation bus voltage based on the power flow through the transformer. The LTC and regulators are mechanical devices that slowly wear with each change of tap. Therefore, the controls on these devices are set with sufficient bandwidth and time delay to avoid excessive wear and maintain the voltage within a range for the customer's equipment to function properly. The capacitor controls are set to manage the reactive power flow while keeping the circuit voltage within the range described above.

Q. May the controls be set to accommodate DER penetration in excess of 15 percent of peak load?

A. No. The traditional LTC and regulator controls were designed assuming the circuit power would only flow from the substation to the loads on the circuit. During conditions of DER power output that exceed the local load, these controls will sense the power flow and adjust the voltage to increase the voltage when it is not desired. Idaho Power would need to replace the controllers with the latest models that are able to detect a reverse power condition and adjust accordingly.

This level of PV penetration can require additional voltage adjustment (tap change) cycles in addition to the daily load cycle adjustments. Adjustments down are needed as the voltage rises with PV output peaking with the solar peak and adjustments up when the voltage decreases during the load peak while the solar output wanes.

Finally, the PV output will change rapidly when broken clouds pass over the PV systems. Rapid changes to output result in rapid voltage fluctuations that cannot be regulated by the time-delayed regulating devices.

Q. Are there operational practices or equipment available to reduce these operational challenges?

A. Yes. Idaho Power first replaces the controllers and optimizes their settings for reduction of voltage deviation without substantially increasing the device wear. Beyond this, there are two options. The first option is to reduce the remaining voltage deviation by decreasing the circuit impedance through full conductor replacement on a given feeder. This option is not practical given that a full conductor replacement would not be cost-effective. The second option is to require voltage regulation from the DER.

IV. INVERTER FEATURES AND FUNCTION

Q. How can on-site generation provide regulation?

A. An on-site generation system interconnected to the grid through a smart inverter can regulate voltage if its voltage control function is enabled.

Q. What is a smart inverter?

A. A smart inverter provides configurable functions beyond the conversion of DC to AC. A few of the features are: voltage/reactive power control, anti-islanding, monitoring, and remote communication.

Q. Have these regulation functions been demonstrated?

A. Yes, multiple studies and experience from Germany, California, and Hawaii have shown that the deployment of smart inverters can reduce the voltage impact of on-site generation. The industry adoption of smart inverter requirements will help to mitigate circuit voltage deviation. States like California and Hawaii have already started requiring smart inverters in residential installations. Germany, the global leader in PV, has required smart inverters for the last few years.

Q. Is there a cost differential between a smart inverter and a standard inverter?

A. Yes, however, smart inverter costs are decreasing and with the adoption of smart inverter requirements in California and Hawaii, these costs will decrease even more rapidly due to scales of production. A standard inverter costs approximately $0.23 per watt whereas a premium inverter with the smart inverter functionality built in costs around $0.35 per watt. For example, if a customer were to install a 6,000 watt system, the price difference between a smart inverter and a standard inverter for this system would be roughly $720.

Most inverter manufacturers already provide smart inverter function capabilities in their devices; it is just a matter of upgrading the software to enable the smart inverter functionality. The manufacturers that do not currently provide smart inverter capabilities in their products are generally lower cost but they will have to offer smart inverter capabilities in the future to remain competitive in the market. The Company recognizes that there is a potential cost difference between lower cost legacy inverters and smart inverters.

Q. Does the Company currently require that customers who install privately-owned generation, interconnect to the grid using a smart inverter(s)?

A. No. The current Schedule 72, Interconnection to Non-Utility Generation, requires that grid interconnected inverters have either a certification with *Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources* UL 1741, Institute of Electrical and Electronic Engineers *Interconnecting Distributed Resources with Electric Power Systems* Standard 1547 ("IEEE 1547") or be subject to third-party testing performed at the customer's expense. None of the standards that are in effect today include a mandate for the use of a smart inverter.

Q. Does the Company believe that it would be beneficial to require Idaho Power customers with privately-owned generation to interconnect to the grid through a smart inverter?

A. Yes. As described previously, the Company believes that many benefits have been demonstrated associated with the use of smart inverters. In fact, the Institute of Electrical and Electronic Engineers are in the process of revising the IEEE 1547 to adopt the standards around what constitutes a smart inverter.

Q. When are the revisions to IEEE 1547 and 1547.1 anticipated to be approved?

A. The IEEE 1547 and 1547.1 standards are presently being balloted. It is anticipated that IEEE 1547 could be approved as early as the end of 2017 and IEEE 1547.1 could be approved by mid-2018.

Q. What is the Company recommending in this filing regarding smart inverters?

A. Idaho Power requests that the Idaho Public Utilities Commission acknowledge that smart inverters provide functionality that is necessary to support the ongoing stability and reliability of the distribution system by ordering the Company to submit a compliance filing in the form of a tariff advice within 60 days of the adoption of the revised IEEE standards, or 60 days of the conclusion of this case, whichever occurs later. This tariff advice will seek to modify Section 2 of Schedule 72 to require that customers with on-site generation install a smart inverter that meets the requirements defined in the revised IEEE standards.

Q. Why would reduction of the voltage deviation, a power quality issue, be the responsibility of the DER?

A. It is the DER that creates the voltage deviation -- it is also the DER that can cost-effectively mitigate the deviation through the installation of a smart inverter. Establishing this as a requirement in Schedule 72 is similar to the requirement for customers to comply with *Practices and Requirements for Harmonic Control in Electric Power Systems* as set forth in the current IEEE Standard 519 in Rule K.

Q. Does this conclude your testimony?

A. Yes.

ATTESTATION OF TESTIMONY

STATE OF IDAHO)
) ss.
County of Ada   )

I, David M. Angell, having been duly sworn to testify truthfully, and based upon my personal knowledge, state the following:

I am employed by Idaho Power Company as the Planning Manager in the Customer Operations Engineering and Construction Department and am competent to be a witness in this proceeding.

I declare under penalty of perjury of the laws of the state of Idaho that the foregoing pre-filed testimony and exhibit are true and correct to the best of my information and belief.

DATED this 27th day of July, 2017.

David M. Angell

David M. Angell

SUBSCRIBED AND SWORN to before me this 27th day of July, 2017.

Kimberly K. Towell

Notary Public for Idaho
Residing at Boise, Idaho
My commission expires: 12/20/2020

KIMBERLY K. TOWELL
NOTARY PUBLIC
STATE OF IDAHO

KIMBERLY K. TOWELL
NOTARY
PUBLIC
STATE OF IDAHO

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-17-13

IDAHO POWER COMPANY

ANGELL, DI
TESTIMONY

EXHIBIT NO. 14

A Method for Determining the Relationship between Solar Irradiance and Distribution Feeder Peak Loading

Phillip Anderson
COEC Research, Development & Deployment
Idaho Power Company
Boise, Idaho USA
PAnderson2@idahopower.com

Brett Efaw and Ellen McKinney
COEC Reliability and COEC T&D Planning
Idaho Power Company
Boise, Idaho USA

***Abstract*—A method for determining the relationship between solar irradiance and distribution feeder peak loading is presented. Two research questions were posed: (1) is there a statistical relationship between solar intensity and load and (2) what other relationships might there be between load and meteorological parameters. A distribution feeder was chosen where data from three equidistant solar irradiance weather stations (SIWSs) was collected between June 21, and September 21, 2013. The data was analyzed using a combination of cross-correlation and maximum cross-correlation / kernel density. The results of the study show that there seems to be a correlation between solar intensity and load, but that correlation is optimally significant when the variables are time-shifted.**

***Index Terms*—Autocorrelation, photovoltaic systems, power distribution, solar energy**

I. Introduction

As electrical power utility customers install their own roof-top photovoltaic (PV) systems, the question arises whether the utility itself could benefit from PV systems that it owns and operates. The effect of cloud cover on PV operability could be less than expected because cloud cover might also have an effect on distribution feeder loading; in other words, as the solar intensity decreases, so also might the loading on an accompanying distribution feeder decrease, or vice versa.

A benefit to a utility when its residential customers begin interconnecting PV systems onto its distribution system might be to balance increasing loads, thus allowing the utility to postpone future feeder upgrades necessitated by load growth. Because of that benefit, a research project designed to collect solar intensity and feeder loading data simultaneously during the summer of 2013 was initiated.

II. A Brief Overview of Existing Research

The existing research of PV system effects on the operations of their distribution feeders yielded three broad categories:

1. Research that addresses distribution feeder simulation that includes PV system interconnection.
2. Research that addresses PV system interconnection that mitigates on-going distribution feeder issues.
3. Research that determines how solar irradiance and cloud cover affects the operation of PV systems on distribution feeders.

Among the research that addresses distribution feeder simulation are Sandia National Laboratories [1] and EPRI [2] each of whom developed software for modeling distribution feeder operation with PV systems interconnected. Additional research in feeder modeling includes determining optimal PV locations and sizing [3]–[4] as well as researching the effects of high-penetration PV onto distribution feeders [5]–[6].

Among the research that addresses PV interconnection as mitigation to on-going feeder issues are using PV systems as non-traditional solutions to distribution feeder problems [7], using PV systems with energy storage for feeder load smoothing [8]–[9], and using PV systems with CVR to manage feeder voltages [10].

Among the research that determines how solar irradiance and cloud cover affects the operation of PV systems on feeders is research of a cloud shadow model to recreate the power generated by rooftop PV systems [11] as well as research of how PV system design can change the dispersion of PV energy across a feeder because of passing clouds [12].

Common to the referenced research is the focus on PV systems interconnected onto a distribution feeder. The research reported in this paper is different because it seeks to find the relationship between solar intensity / cloud cover and a distribution feeder's actual loading. In other words, this research is concerned with how sunshine or clouds may impact the amount of distribution feeder load created throughout the day.

III. Research Design

Two questions formed the basis of the research design:

1. Is there a statistical relationship between solar intensity and load?
2. What other relationships might there be between load and meteorological parameters?

In April 2013, a project was designed to answer the research questions. The scope of the project included the following tasks:

- Study a residential feeder to determine weather / solar monitoring locations.
- Install weather / solar stations and gather solar, weather, and load data.
- Analyze the data for possible correlations.

The research project included purchasing and installing solar intensity monitors, PV panels, and power metering and recording equipment. Studying the relationships between load and meteorological parameters other than solar intensity, wind speed, and ambient temperature were considered to be outside the scope of the project.

The research was limited to data obtained from a single residential feeder typical for the installation of roof-top PV systems; feeders that might host larger, utility-scale installations were considered to be outside the project's scope.

IV. SITE SELECTION CRITERIA

The study feeder is located in a city of approximately 215,000 population. The city's climate is semi-arid, with average monthly sunshine ranging from a peak of 400 hours in July to 105 hours in December [13]. The distribution feeder chosen to host the solar irradiance weather stations (SIWSs) and collect solar irradiance data met the following conditions:

- Covering a geographical distance greater than 3.2 kilometers in an east-to-west direction to be able to track the effects of cloud cover as the clouds move from one SIWS site to the next.
- Being comprised of mostly residential and light commercial customers.
- Being one where the installation of the SIWSs would be as accessible as possible, located near the operating office where the data would be analyzed.

The study feeder is summer-peaking rated 34.5kV and 20MVA. A 34.5kV feeder typically covers a greater geographical area than a 12.5kV feeder, thus being more likely to meet the condition set for geographical configuration. The feeder is configured such that the distance from its eastern-most location to its western-most location is approximately 5.6 kilometers.

Three SIWSs were installed on the feeder at locations that were (1) as geographically equidistant from one another as possible and (2) as free from impediments to irradiance data-gathering as possible.

Each station was initially designed to include global horizontal irradiance (GHI) monitoring, point-of-array (POA) monitoring in the westerly direction, wind speed monitoring, wind direction monitoring, ambient temperature monitoring, and GPS time synchronization. POA monitoring in the southerly direction and globally was added later. Westerly POA monitoring was chosen because of the sun's location at the time of the feeder's 2012 peak. Later, the southerly POA was added to emulate typical PV system installations.

V. DATA COLLECTION

Solar and weather data was captured onto an SD card — at a data capacity of 2G — located in the data logger. At a set time interval, the data was collected by removing the SD card from the data logger, copying the data from the SD card to a laptop's hard drive, deleting the data from the SD card, and replacing the SD card back into the data logger.

The following data was collected from each of the SIWS sites:

- UTC time
- Wind speed (the average over a ten-second interval) in meters / second (m/s)
- Wind gust (the peak over a ten-second interval) in m/s
- Wind direction in degrees (with 0° being North)
- Local battery voltage (over a ten-second interval)
- Ambient temperature in $^{\circ}C$
- Solar irradiance POA South in watts /meter^2 (watts/m^2)
- Solar irradiance POA West in watts/m^2
- Global Horizontal irradiance in watts/m^2

Initially, data was collected every two weeks because of the need to ensure that a minimum amount of data would be lost should an issue with the logger arise. Data was collected on May 24, June 4, July 1, July 15, August 1, August 8, September 12, and October 2. Load data for the feeder was also collected in ten-second intervals to match the times of the collected irradiance data.

VI. DATA ANALYSIS

A. Cross-correlation analysis

To find relationships between solar intensity and load / other meteorological parameters, the data was nominalized so that each variable ranged between 1 and 0. That allowed the two correlated time-series to be more easily relatable when graphed as well as to provide a common axis from which to compare results for different days. Figure 1 shows a typical nominalized load shape and irradiance shape for the westerly-configured sensor on SIWS01 on the system peak load day of July 1, 2013.

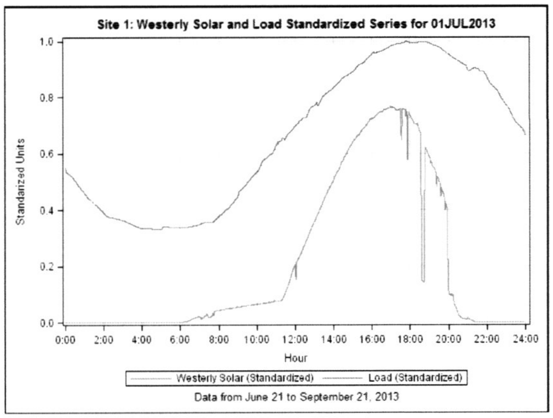


Figure 1. Southerly solar and load, 7-1-2013

Even though data was collected at 10 second intervals, cross-correlations were calculated at 5-minute intervals to allow for quicker computation. For each correlation, the load time-series was held constant while the other time-series — southerly, global, and westerly sensor configurations; temperature; and wind speed — were shifted across a ±12-hour range. Cross-correlations were graphed for each of the 93 days of the study at each of the three SIWSs. Fifteen cross-correlation computations were made for each day of the study at each of the three SIWSs, resulting in the production of 4915 cross-correlation graphs.

For the July 1, 2013, SIWS01, example Figures 2 through 4 show the graphs of the various cross-correlation calculations at ±12 hours:

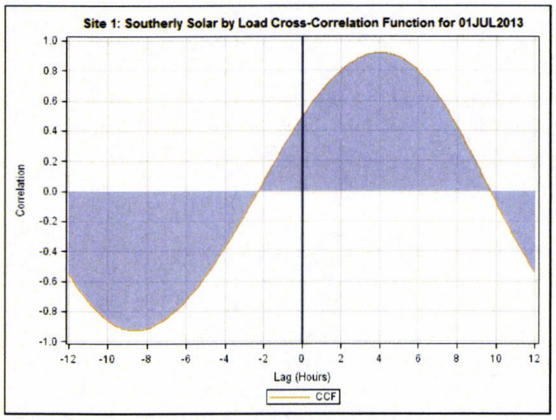


Figure 2. Cross-correlations for Southerly Solar and load at SIWS01 on 7-1-2013

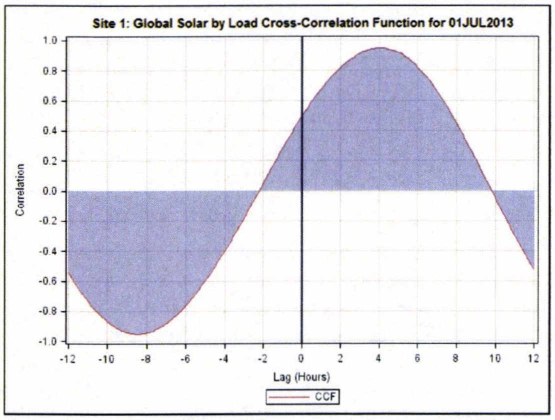


Figure 3. Cross-correlations for Global Solar and load at SIWS01 on 7-1-2013

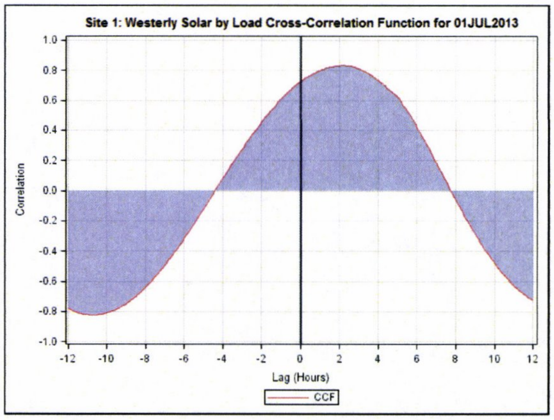


Figure 4. Cross-correlations for Westerly Solar and load at SIWS01 on 7-1-2013

For the clear and sunny July 1, 2013, the correlations between the sensor configuration's time series and the load's time series are fairly significant. For the worst case westerly configuration versus load, the maximum correlation of 0.81 occurred when the feeder's load data lagged the solar intensity data by two hours. On the same day and SIWS, the maximum correlation was 0.90 when the load data lagged the solar intensity data by four hours on the southerly-facing sensor, and the maximum correlation was 0.92 when the load data lagged the solar intensity data by four hours on the global sensor.

B. Maximum cross-correlations / kernel densities

While the cross-correlations provided information relating to the relationships between irradiances and loads for each of the individual days of the study period, the question remained regarding if any relationships over the entire 93-day study period could be identified. To answer that question, maximum cross-correlations were calculated to create kernel densities.

For each time series pair, the maximum cross-correlation and the time lag when the maximum cross-correlation occurred were identified for each day of the study period. Next, the results from each day were used to estimate a bivariate kernel density for each pair of time series. This bivariate density estimate yielded a point that represented the most common occurrence over the course of the study for the strength of the linear relationship and the amount of time the offset occurred. The ranges of both the linear relationship and the offset in time were also observed from the bivariate density estimates.

The density plots in Figure 5 show, for SIWS01, the estimates between the load and the southerly sensor configuration for solar intensity both 2-dimensionally and 3-dimensionally.

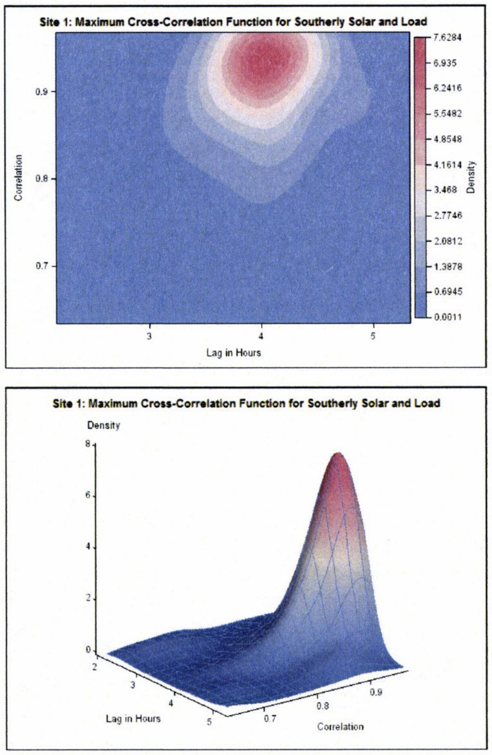


Figure 5. Example kernel density for SIWS01 southerly solar versus load over the study period

The most common daily occurrence was a strong linear relationship of 0.94 between the solar intensity and load lagged by approximately four hours. Over the course of the entire summer, the range of the strength of the relationship was generally greater than 0.80 with the lag generally between three and five hours.

For each of the three SIWSs, twelve kernel densities were calculated that showed irradiances versus load relationships, irradiances versus ambient temperature relationships, and irradiances versus wind speed relationships. It was from analyzing these thirty-six calculations that the results of the study, and answers to the research questions, were formed.

VII. Results

A. Relationships to load

First, there seems to be a statistical relationship between solar intensity and load, but with the understanding that correlation does not imply causation.

- Solar intensity analyzed at the southerly-configured sensors tends to lead load from 3.96 to 4.13 hours with a correlation of 0.94 across all three SIWS locations.
- Solar intensity analyzed at the global-configured sensors tends to lead load from 4.00 to 4.02 hours with a correlation ranging from 0.95 to 0.96.
- Solar intensity analyzed at the westerly-configured sensors tends to lead load from 1.76 to 1.94 hours with a correlation ranging from 0.88 to 0.91. The curves of the westerly-configured irradiances tend to peak closer to the time of feeder peak loads, but with lower certainty than the southerly- and global-configured irradiances.

Next, there seems to be a strong correlation between ambient temperature and load data, but a tepid correlation between wind speed and load data.

- Ambient temperature tends to lead load from 0.70 to 0.86 hours with a correlation ranging from 0.96 to 0.97 across all three SIWS locations. While not a surprising result, what was a little surprising was the range in lead time between the three SIWSs.
- Wind speed tends to lead load from 1.80 to 2.38 hours with a correlation ranging from 0.68 to 0.70 across all three locations. This tepid statistical relationship between wind speed and load also was not surprising considering the low auto-correlation of wind speeds.

B. Disclaimers

When drawing conclusions based upon the analysis of the data, a few disclaimers need to be considered.

- The conclusions are limited by the study time period. The conclusions would likely have been different if data had been analyzed for seasons other than summer.
- The conclusions are limited by the locations of the study's SIWSs. The conclusions would likely have been different if data had been collected (1) from a different type of feeder or (2) from a different geographical area.

These disclaimers, however, can also be considered opportunities to continue the research to test the statistical methods and analysis used in the study.

VIII. Discussion

A. Lessons learned from the research design process

As with most research, the most difficult part of the design was choosing and applying the most appropriate statistical tool. After the data was collected, an iterative process ensued, beginning with making a simple correlation between daily peak loads and daily peak irradiances, and realizing that using such a tool with two variables that were clearly unrelated yielded unsatisfactory results. Time-shifting the data, first though the auto-correlations and then cross-correlations, provided a means of accessing the daily relationships between the variables. Finally, applying maximum cross-correlations and plotting kernel densities allowed the statistical relationships — calculated over the entire 93-day study period — to emerge. Any similar research in the future will also need to implement a cross-correlational / maximum cross-correlational / kernel density approach to data analysis.

A couple decisions made early in the research design positively affected the ability to answer the research questions: the choice to collect the data from irradiance sensors rather than from solar panels, and the choice to add a southerlyexposed sensor to the global and westerly sensors at each of the three SIWSs. The decision to collect data from three somewhat equidistant locations along the feeder route, while not necessary for answering the research questions, did provide the opportunity to validate the data collected and will be a source of analysis of geographical relationships between the variables.

B. *Possible applications of the research results*

The analyzed data set has already been implemented. The data has been used with OpenDSS software to perform generation interconnection studies of utility-scale PV systems. Other applications of the data have been in assisting with resource planning as part of the utility's integrated resource plan and in collaboration with Sandia National Laboratories for their variability and GHI to POA conversion studies. Probably the most interesting possibilities for applying the research results would be for:

- Recommending preferred PV orientations to commercial customers for their rooftop applications that would best support reducing the effects of feeder summer peak loads.
- Designing a demonstration project of a PV system coupled with energy storage to extend peak load reduction at the end of a distribution feeder.

C. *Opportunities for further research*

Data continues to be collected from the three SIWSs beyond the initial study period, resulting in more than a year's worth of data having been collected. Opportunities have been identified regarding additional studies that could be made with the study data as well as with the additional data collected post-study.

1) *Using this research study's data.*

The SIWSs were geographically configured along the feeder route, spaced equidistant from one another. While that fact was not pertinent in answering the research questions, it could generate a follow-up research project to determine the geographical relationships between irradiance data collected from the three SIWS sites. The data collected could be also be used to calculate the solar energy density (Watt-hours/m^2) per time interval for each site at each solar intensity orientation. Another use of the research data could be to run irradiance statistics over a multiple-day time period to see if a relationship is evident as a predictor of the seasonal peak load.

Finally, the data could be used in combination to determine how PV installation for home- and business-owned systems could provide optimal benefit the utility.

2) *Branching out from this research study data.*

Other interesting areas for further research can be sorted according to (1) using the additional data that has been collected subsequent to the study period and (2) implementing additional types of research design protocols. Some ideas for using the additional data collected include:

- Analyzing data from other seasons of the year, such as the time of the feeder's winter peak load or the time of the feeder's minimum peak load.
- Analyzing cross-correlations of solar irradiance to wind to find any complimentary relationships.
- Analyzing data collected in summer 2014 compared to data collected in summer 2013.

Some ideas for implementing additional design protocols include:

- Determining what effects humidity might have on solar intensity and load.
- Including cross-correlations of the loads from adjacent feeders to follow the effects of cloud cover.
- Analyzing data from additional feeder types where solar might be of interest.
- Including volatility in irradiance statistical analyses.
- Correlating wind speed to solar volatility.
- Designing a study similar to this research design for a winter-peaking area.

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