and reduced installation costs for LED street lights. Currently, there are no LED SL customers, so the proposed LED changes will not affect any current customers.

9. Rates for Distributed Generation Customers, Rate Nos. 59 and 67

a. Distributed Generation in New Mexico

Q. What is distributed generation?

A. Distributed generation ("DG") means electric generation sited at a customer's premises, providing electric energy to the customer load at that site or providing electric energy to a public utility or a rural electric distribution cooperative for use by multiple customers in one or more contiguous distribution substation service areas.

Q. Does the Public Utility Act address cost recovery from DG customers?

A. Yes. Section 62-13-13.2(A) of the Public Utility Act ("PUA") authorizes the Commission to approve "interconnected customer rate riders to recover the costs of ancillary and standby services." In establishing such riders, the Commission shall assure that the costs to be recovered through the rate riders are not duplicative of costs to be recovered in underlying rates and "shall give due consideration to the reasonably determinable embedded and incremental costs of

the utility to serve new interconnected customers and the reasonably determinable benefits to the utility system provided by new interconnected customers."

Q. Does Section 62-13-13.2 define "ancillary and standby services"?

A. Yes. Section 62.13-13.2(D)(1) defines "ancillary and standby services" to be those "services that are essential to maintain electric system reliability and are required by or are a consequence of interconnecting DG facilities to a utility's system and may include, among other services, regulation and frequency response, regulation and voltage support, spinning reserves, and supplemental reserves." Because the statute uses the word "and" between "ancillary" and "standby," I interpret it, as a rate design expert with experience implementing and applying statutory provisions applicable to ratemaking, to be defining two separate and distinct "services" – ancillary services and standby services. I do not intend to offer legal opinions about what the terms in the statute mean, as I am not an attorney, nor have I undertaken any research to determine how the Commission may have interpreted the statutory language. However, my interpretation of the statute is consistent with my understanding – based on nearly

four decades in the utility industry – that standby services and ancillary services are different types of service.[2]

Q. The term "fixed costs" is used in § 62-13-13.2(B), and term "costs of ancillary and standby services" is used in § 62-13-13.2(A) and defined in § 62-13-13.2(D)(1). As a rate design expert with experience implementing and applying statutory provisions applicable to ratemaking, and not as someone offering a legal opinion, how do you read the terms "fixed costs" and "costs of ancillary and standby services" for purposes of establishing rates?

A. The term "fixed costs" is not defined in § 63-13-13.2, but economics texts generally refer to "fixed costs" as those costs that do not change as a result of changes in output or consumption levels. In the utility industry, a fixed cost is one that does not change with each new kWh of energy produced or each new kW of demand met. For example, a utility's salary and rent expenses are generally fixed over a period of time, such as a year, and those salaries and rent amounts do not vary in accordance with the number of kWh or kW sold. Accordingly, they are considered "fixed costs."

[2] The statute also mentions several types of ancillary services as examples, but the list is not exclusive. There can be other types of ancillary services, and SPS witness William A. Grant discusses several other types of ancillary services in his direct testimony.

In a comparison of fixed costs, ancillary services, and standby services, I consider ancillary services to be the most well-defined term, as well as the narrowest term. As Mr. Grant explains in his direct testimony, the SPP Open Access Transmission Tariff expressly prescribes the ancillary services that SPS is required to acquire or provide. Other New Mexico utilities likely are subject to similar ancillary service requirements.

The phrase "fixed costs" in NMSA 1978, § 62-13-13.2(B) is less well-defined, but based on the definition I set forth earlier, I interpret it, for my purposes of designing rates, to mean the costs that do not change with changes in output or consumption levels. Thus, from a rate design perspective, rural electric cooperatives are allowed to recover their fixed costs through the rider applicable to standby customers. To the extent cooperatives incur fuel or variable O&M costs as a result of providing service to standby customers, they must recover those costs through other rate mechanisms.

Finally, the term "standby service" is not defined in the statute, nor is it clearly defined in common usage outside the utility industry, but based on my experience in the utility industry, I would consider it to be the broadest of the three terms. To provide standby service, a utility must size its production, transmission, and distribution facilities in a way that allows it to serve a standby

customer's full load. In addition, the utility may incur other types of costs necessary for it to serve that standby load, and the Legislature did not place any limits on the types of costs that a utility can recover in connection with its provision of standby service to interconnected customers.

Q. In implementing the statute as a rate design expert, and not as someone offering a legal opinion, do you have any other reasons for concluding that the costs associated with "standby service" can be broader than "fixed costs"?

A. Yes. In NMSA 1978, § 62-13-13.2(C), the Legislature provided that "Nothing in this section shall be interpreted as preventing the utility from charging rates designed to recover all of its reasonable costs of providing service to customers." Notably, that section does not provide assurances that a "utility or cooperative" will be allowed to charge rates that are designed to recover all reasonable costs. The provision is limited to a "utility," which is the same term used in subsection (A). Reading subsections (A) and (C) in combination leads to the conclusion, for my purposes in applying the statute for designing rates, that an investor-owned utility must be allowed to recover *all* of the costs incurred to serve standby customers, regardless of whether those costs are labeled as fixed costs or other

types of costs. In contrast, a cooperative is limited to recovery of "fixed costs" through the rider authorized by NMSA 1978, § 62-13-13.2.[3]

As a practical matter, the difference between the costs of "standby service" and "fixed costs" may be very small. Because SPS recovers its fuel and purchased power costs through the Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC"), the only costs that are recovered through base rates are fixed costs.

Q. As a rate design expert who needs to apply statutes for the purpose of designing rates, is your understanding of the scope of "standby services" the same as the language in § 62-13-13.2 that limits the cost of standby service to services "that are essential to maintain electric system reliability and are required by or are a consequence of interconnecting DG facilities to a utility's system"?

A. No, for several reasons. First, SPS operates its production, transmission, and distribution facilities as a unified system and all parts of it are necessary to maintain system reliability. Standby customers are using their allocated portion

[3] I note that cooperatives are subject to less ratemaking oversight by the Commission than investor-owned utilities are. For example, under § 62-8-7(H), a cooperative's base rate increase can take effect without a hearing by the Commission unless cooperative customers file a protest to the proposed rate increase. In contrast, an investor-owned utility cannot implement any rate increase without advanced Commission approval (provided the Commission has suspended the proposed rate increase within thirty days of the date the utility filed its advice notice).

of that system to serve their load when their DG resources are not adequate to serve the load. Stated differently, standby customers require use of far more of SPS's system than just the production meters and the local distribution upgrades that might be required to interconnect their specific DG facilities.

Second, for purposes of implementing the statute to design rates, I do not interpret the phrase "are required by or are a consequence of interconnecting DG facilities to a utility's system" to limit recovery to only the costs associated with particular DG facilities. As I have explained, SPS operates its production, transmission, and distribution system as a whole, and all of those facilities are required to serve DG facilities. I also explained that SPS's production, transmission, and distribution facilities are sized to serve all of the customers, including standby customers, so the overall costs of the system are required by or a consequence of interconnecting DG customers (and all other customers) to SPS's system.

Third, for my purposes of designing rates, interpreting the statutory language quoted in the question to apply only to incremental costs associated with interconnecting or serving a standby customer would require non-standby customers to pay the fixed costs that are incurred in part to serve standby customers. The Legislature certainly could choose as a policy matter to require

that non-standby customers subsidize standby customers, but that would run counter to the well-settled ratemaking principle that customers should pay the costs of facilities used to serve them, unless there is a compelling reason otherwise.

Finally, for my purposes of designing rates, a reading of the statute that limits standby service costs to the incremental costs incurred to serve a standby customer leads to a poor outcome from a policy perspective, in my view. As I explained earlier, that interpretation would result in more and more of the fixed costs attributable to a class to be shifted to non-standby customers, and the customers burdened with the additional costs would be the least able to afford them. That burden is relatively light right now for most customer classes, but it will continue to grow as DG, particular rooftop solar, increases in New Mexico.

Q. In applying the statute for purposes of designing rates, is there a rate design distinction between "fixed costs," as used in NMSA 1978, § 62-13-13.2(B), covering both demand and customer-related costs versus "costs of ancillary and standby services," as used in § 62-13-13.2(A) and defined in § 62-13-13.2(D)(1) including only demand costs?

A. For rate design purposes, I agree that the term "fixed costs" can include both demand and customer-related costs. I do not agree that ancillary services costs

include only demand costs. As I have explained, most of the costs of ancillary services are energy-related, meaning that those costs are not intended to reflect either demand or customer-related costs.[4] However, the three types of ancillary service costs that are in base rates, which are Schedule 1, Schedule 1A, and some Schedule 2 costs, would likely be recovered through demand charges, rather than customer charges. Standby service costs could be recovered through either demand charges or customer charges because SPS incurs both demand costs and customer costs to interconnect and serve standby customers.

Q. From a rate design perspective and your need to apply a statute for ratemaking purposes, if the term "fixed costs" as used in § 62-13-13.2(B) is broader in meaning and in scope than the term "costs of ancillary and standby services" as used in § 62-13-13.2(A) and defined in § 62-13-13.2(D)(1), what types of costs may be recovered as "fixed costs" but not "costs of ancillary and standby services"?

A. As I have explained, from a rate design perspective, the phrase "costs of . . . standby services" can be broader in meaning and scope than "fixed costs," but because SPS recovers the vast majority of its non-fixed costs through the

[4] Mr. Grant's direct testimony explains why the ancillary service costs are considered to be energy-related.

FPPCAC, the two phrases are largely synonymous as a practical matter. "Fixed costs" is broader in meaning and scope than "costs of ancillary" services because most of the ancillary services costs are energy-related only, and the remaining ancillary service costs recover only demand costs. The costs that I describe in response to following question could be recovered as fixed costs and standby costs, but not as energy-related ancillary services.

Q. State whether, from a ratemaking perspective, the following categories of costs are "fixed costs," "costs of ancillary and standby services" or both:

i. salaries
ii. rent
iii. depreciation
iv. insurance
v. postage
vi. office buildings
vii. substations
viii. return on equity

A. In my opinion, all of the listed categories of costs qualify as both "fixed costs" and "standby services" costs. Only a few of the listed costs are recovered as part of ancillary service charges.

Q. Why are most of the categories of costs in preceding question not included in ancillary service charges?

A. As I testified earlier, all of the ancillary services costs except those charged under Schedule 1, Schedule 1A, and portions of Schedule 2 are energy-related variable

costs, and SPS recovers its energy-related charges in accordance with the FPPCAC.

Q. Does SPS recover any of the categories of costs listed above through Schedule 1 charges?

A. Yes. As Mr. Grant explains, Schedule 1 relates to the scheduling of power within the SPP footprint. The salaries of SPS and Xcel Energy Services Inc. employees who interact with SPP to schedule power on behalf of SPS are included, in whole or in part, in the FERC accounts used to calculate Schedule 1 charges. The depreciation attributable to certain equipment used for the scheduling function is also included in Schedule 1 charges. None of the other categories of costs are included in Schedule 1 charges.

Q. Does SPS recover any of the categories of costs listed above through Schedule 1A charges?

A. No. As Mr. Grant explains, Schedule 1A fees recover the SPP administrative fee. Therefore, those fees are designed to recover SPP's costs, not SPS's costs.

Q. Does SPS recover any of the categories of costs listed above through Schedule 2 charges?

A. The Schedule 2 charges and revenues originally contained a depreciation component designed to compensate the generator providing the Schedule 2

service with recovery of depreciation expense associated with the generating unit providing voltage regulation. Since the beginning of the SPP Integrated Marketplace, however, the Schedule 2 revenue requirements no longer contain an explicit provision for depreciation expense. In any event, the annual amounts of Schedule 2 revenues and costs are so small that they have no material effect on SPS's New Mexico retail revenue requirement.

b. SPS's DG Rates in New Mexico

Q. Does SPS currently have rates applicable to DG customers for standby service?

A. Yes. Depending upon the standard service applicable to each DG customer, Rate Nos. 59 and 67 apply to DG customers. Both rates address the recovery of Production, Transmission, and Distribution capacity costs resulting from SPS standing by to provide those services at any given time throughout the year to customers with customer-owned generation. Rate No. 59 is SPS's "Distributed Generation Standby Service Rider," which was established under PUA Section 62-13-13.2. SPS applied to establish and implement Rate No. 59 in Case No.

10-00196-UT, a Renewable Portfolio Standard proceeding.[5] In that proceeding, SPS proposed to collect from DG customers a portion of the transmission, distribution, and production costs associated with SPS's obligation to serve these customers regardless of whether the customers' DG facilities produced energy on a given day. To comply with § 62-13-13.2, SPS witness Donald E. Garretson presented a comprehensive study in Case No. 10-00196-UT that analyzed both the reasonably determinable costs and off-setting benefits associated with SPS's obligation to provide standby services to its DG customers. In particular, that study determined the appropriate level of standby costs associated with transmission, distribution, and production capacity, and it incorporated existing benefits into the proposed Standby Rate Rider.[6] To determine the amount of costs that would be collected from DG customers, SPS proposed to apply a percentage "unavailability factor" because SPS was only required to "have standby

[5] *See* Case No. 10-00196-UT, *In the Matter of Southwestern Public Service Company's Annual Renewable Portfolio Report for 2009 and its Application for Approval of (1) its 2010 Annual Renewable Energy Portfolio Procurement Plan; (2) Request for a Variance from Rule 572.14; and (3) Approval of Associated Tariffs,* Recommended Decision at 26-31 and Decretal ¶ 5(Nov. 23, 2010), adopted by Final Order (Dec. 23, 2010).

[6] *In the Matter of Southwestern Public Service Company's Annual Renewable Portfolio Report for 2009 and its Application for Approval of: (1) its 2010 Annual Renewable Energy Portfolio Procurement Plan; (2) Request for a Variance from Rule 572; and (3) Approval of Associated Tariffs*, Case No. 10-00196-UT, Rebuttal Testimony of Donald E. Garretson at 6 (Oct. 7, 2010).

production backup equal to the average percent of time that the particular DG system is unavailable."[7] The unavailability factor was calculated to represent the back-up production that must be maintained to serve load when DG systems are not available.[8] SPS addressed the reasonably determinable benefits of new DG customers to SPS's system by proposing to adjust the amount of costs attributable to DG customers downward by 50% to account for those benefits.[9] In addition, Mr. Garretson proposed that SPS would prepare a study for use in its next base rate case to "determine if there are any *other* quantifiable benefits and offsetting costs for renewable DG [not reflected in the study SPS presented in Case No. 10-00196-UT] based on program participation and development in the future."[10]

Q. Did the Hearing Examiner in Case No. 10-00196-UT make any recommendations to the Commission concerning SPS's proposed Standby Rate Rider?

A. Yes. The Hearing Examiner found that SPS's proposed Standby Rate Rider was supported by the preponderance of the evidence, and that the study SPS

[7] *See* Case No. 10-00196-UT, Direct Testimony of Donald E. Garretson, at 13.

[8] *Id.*

[9] *Id.* at 18.

[10] Case No. 10-00196-UT, Rebuttal Testimony of Donald E. Garretson at 6 (emphasis added).

performed in support of the rider "satisfies the statutory requirements for Commission approval."[11] The Hearing Examiner recommended that the Commission approve SPS's request to recover the costs of standby service under its proposed Standby Rate Rider, Rate No. 59.[12]

Q. Was the Hearing Examiner's recommendation that the Commission approve SPS's proposed Standby Rate Rider conditioned on SPS performing the future study proposed by Mr. Garretson?

A. No.

Q. Did the Commission approve SPS's proposed Standby Rate Rider consistent with the Hearing Examiner's recommendation?

A. Yes, the Commission adopted the Recommended Decision authorizing Rate No. 59, and expressly determined that the rate met the requirements of Section 62-13-13.2.[13]

[11] Case No. 10-00196-UT, Recommended Decision of the Hearing Examiner at 31 (Nov. 23, 2010).

[12] Case No. 10-00196-UT, Recommended Decision of the Hearing Examiner at 36 (Nov. 23, 2010).

[13] *See* Case No. 10-00196-UT, Recommended Decision at 25-31 and Decretal¶ F (November 23, 2010), Final Order (December 23, 2010).

Q. Did the Commission re-examine Rate No. 59 following Case No. 10-00196-UT?

A. Yes. As required by Section 62-13-13.2, Rate No. 59 was reviewed again in Case No. 10-00395-UT, SPS's next general rate case following Case No. 10-00196-UT. In Case 10-00395-UT, SPS proposed to replace Rate No. 59 with Rate No. 67, "Standby Service Rider," for demand-metered customers. SPS explained that its proposal responded to concerns that Rate No. 59 was duplicative of those customers' demand charges. In that case, the Commission approved an uncontested comprehensive stipulation, under which SPS revised Rate No. 59 as proposed and established Rate No. 67.

Q. Has SPS conducted the study Mr. Garretson proposed in Case No. 10-00196-UT?

A. No, for two reasons. First, there was not time to complete the study between the date the Commission entered its final order in Case No. 10-00196-UT (December 23, 2010) and the date SPS filed its next base rate case after Case No. 10-00196-UT. SPS filed that next base rate case on February 28, 2011 (Case No. 10-00395-UT). Second, given that in Case No. 10-00196-UT the Commission found that the study SPS provided in that case satisfied the statutory requirements and did not state that the proposed additional study was necessary, SPS did not

prepare an additional study for the base rate cases SPS filed after it filed Case No. 10-00395-UT.

Q. Did you perform a study in this case to support SPS's proposed rates for DG customers under Rate No. 59?

A. Yes. The rates SPS is proposing for Rate Nos. 59 and 67 in this case are based upon the costs and the analyses SPS is presenting in this case—not on any costs or analyses presented in prior cases. As I noted earlier, however, the Commission stated in Case No. 10-00196-UT that the type of study and level analysis that SPS has presented in that case met the statutory requirements for establishing standby rates. Although I am not relying upon the level of costs, data, or the specific analyses SPS presented in that case (or in any other case) as the factual bases for the proposed costs to be recovered through Rate Nos 59 and 67 in this case, I am employing the same type of study and level of analysis that the Commission found acceptable in Case No. 10-00196-UT.

Q. Did the Commission approve changes to SPS's DG rates in Case No. 15-00296-UT?

A. Yes, the Commission approved a stipulation in which the parties agreed to changes to Rate Nos. 59 and 67.

Q. Page 31 of the Certification of Stipulation issued in Case No. 15-00296-UT states that the Rate No. 59 tariff in the Stipulation approved in that case "reflects a negotiated compromise of certain controversial issues embedded in the DG rider." Without disclosing any confidential settlement communications that occurred in Case No. 15-00296-UT, please explain what controversial issues embedded in the DG Rider were resolved through that Stipulation.

A. It is my understanding that the reference to "controversial issues" on page 31 of the Certification of Stipulation refers to issues addressed in a series of pleadings related to Vote Solar's and Coalition for Clean Affordable Energy's ("CCAE") joint motion to dismiss SPS's proposed increases to Rate No. 59 on the grounds that SPS: (1) failed to meet its burden of proof regarding its proposed change to Rate No. 59; (2) violated the Commission's filing and notice rules regarding Rate No. 59; and (3) sought to recover costs that are not authorized by NMSA 1978, Section 62-13-13.2. That series of pleadings consisted of:

1. Vote Solar and CCAE Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59, and Supporting Brief;[14]

[14] *In the Matter of Southwestern Public Service Company's Application for Revision of Its Retail Electric Rates Pursuant to Advice Notice No. 256*, Case No. 15-00296-UT, Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59, and Supporting Brief (Mar. 8, 2016).

2. SPS's Response to Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59;[15]

3. Utility Division Staff of the New Mexico Public Regulation Commission's Response to Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59;[16] and

4. Vote Solar and CCAE's Joint Motion for Leave to Reply to SPS's and Staff's Responses to Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59.[17]

The Stipulation in Case No. 15-00296-UT eliminated the need to resolve the controversial issues raised by these pleadings. The Certification of Stipulation in that case acknowledged this fact.[18] The controversial issues were not the three aspects to Rate No. 59 that the Certification of Stipulation listed on page 31. Those aspects listed on page 31 describe characteristics of the Rate No. 59 tariff that resulted from the compromise, but those aspects are not a list of the controversial issues.

[15] Case No. 15-00296-UT, SPS's Response to Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59 (Mar. 21, 2016).

[16] Case No. 15-00296-UT, Staff's Response to Vote Solar's and CCAE's Joint Motion to Dismiss SPS's Proposed Increases to Rate 59 (Mar. 21, 2016).

[17] Case No. 15-00296-UT, Joint Motion for Leave to Reply to SPS's and Staff's Responses to Joint Motion to Dismiss SPS's Proposed Increases to Rate No. 59 (Apr. 4, 2016).

[18] Case No. 15-00296-UT, Certification of Stipulation at 37 (Jul. 22, 2016).

Q. Please state the number of customers in each class that takes service under Rate Nos. 59 and 67.

A. The number of customers in each class is provided in the table below:

Table EDE-1

Rate 59	
Residential	112
Small General	14
Irrigation	29

Rate 67	
PG	5
LGST 115+	3

i. Rate No. 59

Q. Is SPS seeking to change Rate No. 59 in this case?

A. Yes. SPS is proposing to adjust the rates applicable under Rate No. 59 comparable to the increases in capacity costs applicable to the corresponding standard rate, but is not proposing any structural changes in how the rate is applied.

Q. Which classes of customers are affected by SPS's proposed change to Rate No. 59?

A. With Commission authorization, Rate No. 59 will continue to apply to customers with DG in the following customer classes: Residential Service, Small General Service, Small Municipal and School Service, and Irrigation Power Service.

Q. Are the costs that SPS is seeking to recover through Rate No. 59 duplicative of costs to be recovered in SPS's underlying rates?

A. No. Revenue from Rate No. 59 billings offsets costs billed through the associated energy charge applicable under standard service rates. If Rate No. 59 was not applied to DG customers, costs are shifted to standard service customers for the Production, Transmission, and Distribution capacity necessary to provide service to DG customers at any time the DG installation is inadequate. There is no double-billing to DG customers for the same set of costs because a kWh delivered and billed to a DG customer is billed under the applicable standard service rate. Rate No. 59, on the other hand, is applicable to kWh generated and used by the DG customer whether the DG kWh is used directly by the customer, or if the kWh is delivered to the SPS system and is used to reverse billing for kWh provided by SPS at other times during the billing period.

It is important to recognize that, with mandatory net metering as required by the Commission,[19] the billing for SPS-delivered power to DG customers is fully reversed if the customer's DG installation generates more power than the customer can use at any given time and delivers that excess power to the SPS

[19] *See* 17.9.570.14(C) NMAC.

distribution system. Thus, even if the DG customer takes power from SPS throughout the month, in the absence of Rate No. 59, it is possible that SPS would not be able to recover costs associated with the ability to provide that power. Rate No. 59 recovers a portion of the fixed capacity costs required for the availability of SPS-provided power any time the DG customer's installation is inadequate or unavailable in meeting the customer's power demands.

Q. Please describe the types of "fixed capacity costs" that Rate No. 59 recovers.

A. Fixed capacity costs are the result of SPS's obligation to provide service to its customers, including standby service customers. Examples of fixed capacity costs include:

- the return on SPS's rate base;
- depreciation expense associated with SPS's production, transmission, distribution, and general plant;
- O&M expense associated with generating stations, T&D facilities, and other types of facilities;
- Administrative and General ("A&G") expense, such as salaries, benefits, and insurance;
- capacity costs included in power purchase agreements ("PPA"); and
- taxes, including both income tax and taxes other than income tax.

Q. Please categorize these "fixed capacity costs" recovered by Rate No. 59 as: (i) fixed costs; (ii) costs of ancillary and standby services; or (iii) both.

A. The fixed capacity costs recovered by Rate No. 59 include both fixed costs and standby services costs. In addition, a limited amount of ancillary service expense recorded in O&M FERC accounts may be considered fixed capacity costs as well.

Q. For each category of "fixed capacity costs" recovered by Rate No. 59, please explain why those costs are considered to be: (i) fixed costs; (ii) costs of ancillary and standby services; or (iii) both.

A. Each category of costs that I listed earlier as an example of a fixed capacity cost is a fixed cost because it does not vary with output. That is, over the short run, SPS's return, depreciation expense, O&M expense, A&G expense, capacity costs, and tax expense are fixed. They do not rise or fall according to the number of kW or kWh sold. All of those components of costs are also standby services because they are all necessary to provide service to standby customers. Finally, a small amount of salary and depreciation expense qualifies as a fixed capacity cost because it is included in the ancillary service expense recovered through base rates.

Q. Is it actually necessary for SPS to recover from its customers as a whole, collectively both standby customers and non-standby customers, all of those elements of cost you listed earlier that SPS incurs to be in a position to provide standby service to customers?

A. Yes. It is necessary to recover those costs from someone. If Rate No. 59 was not in effect, SPS would have to recover the cost of providing standby service from non-standby customers. As I testified earlier, I do not believe the Legislature intended for non-standby customers to provide that type of subsidy to standby customers.

Q. Above you stated that if Rate No. 59 is not applied to DG customers, then costs would be shifted to standard service customers. How would that shift occur?

A. The cost shift would occur in the rate design step. After costs are allocated to each class, the rates for each class are then designed to recover all of the costs that have been allocated to that class. If DG customers are excluded from consideration when designing the rates for that class, then DG customers obtain standby capacity service from SPS at no charge, with the result that capacity costs associated with standby service to that class will be recovered solely from customers taking standard service.

Q. In designing SPS's proposed Rate No. 59, did SPS balance its reasonably determinable embedded and incremental costs to serve new DG with the reasonably determinable benefits of new DG customers to SPS's system?

A. Yes. The interconnection of DG to the SPS system behind the meter does not eliminate the cost to provide service to the same customer. If the customer's DG installation is sufficiently large, it is possible that the DG customer can fully reverse the charges for power delivered by SPS as a result of net metering. Even if the customer's system is designed to generate the same amount of kWh during a month as the customer actually uses, there would still be interconnection costs and other, fixed costs that would not be eliminated.

For example, it is still necessary to provide a connection and the meter that will enable SPS to meter consumption and to provide service to the DG customer, particularly during all hours and during any second in which the DG system does not fully supply the customer's energy requirements. The cost of connecting a DG customer is higher than the cost to connect a standard service customer because SPS must provide the facilities to not only provide service to the DG customer, but also to safely receive excess power from the DG customer in a

manner that does not risk reliability of SPS-provided power to the DG customer as well as the DG customer's neighbors.

In addition, a DG system provides energy that can partially or fully eliminate the energy or demand requirements of customers during some hours of the day and because the systems are located behind the meter, they will also reduce the losses on SPS's system. However, because the typical small, customer-owned DG system connected to SPS is a fixed, solar photovoltaic ("PV") power system, the output of these systems will vary significantly throughout the day and these systems can only be expected to produce near their rated capacity for a fraction of the hours during the year. Therefore, the ability of these systems to mitigate a customer's instantaneous peak loads or hourly energy requirements is limited.

Q. Has SPS analyzed how a typical, customer-owned solar DG facility will affect a customer's peak demand requirements on SPS's system?

A. Yes. Attachment EDE-6 to this testimony identifies the impact that a 1 kW-AC PV power system would have on SPS's system production and transmission four summer monthly coincident peak ("4CP") demands. Attachment EDE-6 reveals that a PV power system rated at 1 kW-AC (1,000 watts) would reduce the

production 4CP demand by 231.19 Watts and the transmission 4CP demand by 178.81 Watts, only 23.12% and 17.88% of rated capacity. In addition, it identifies how much a 1 kW-AC PV system connected behind the meter would reduce the annual NCP demand for each of the customer classes served under Rate No. 59. The impacts range from a low of zero for Irrigation Service to a high of 888.70 Watts for Small Municipal and Schools Service.

In addition, Attachments EDE-7 through EDE-10 to this testimony identify the typical hourly loads in July for an average Residential Service, Small General Service, SMS, and Irrigation Service customer. These attachments also compare the hourly generation from PV systems sized to supply the same amount of kWh as the average customers' consumption in each customer class in July to the typical hourly loads in July for average customers in each class. For each hour and each class, these graphs identify the amount of excess energy supplied by the PV system and the amount of energy supplied by SPS.

Q. Can SPS include the capacity of renewable DG systems in meeting its system power requirements?

A. No. DG systems provide non-firm capacity and energy. Thus, SPS cannot include the capacity in meeting its system power requirements.

ii. Rate No. 67

Q. Is SPS seeking to change Rate No. 67 in this case?

A. SPS is proposing to adjust the rates applicable under Rate No. 67, but is not proposing any structural changes in how the rate is applied. Rate No. 67 is available to Primary General Service, Secondary General Service, LMS, and LGS-T customers that have customer-owned generation.

Q. How does Rate No. 67 address the concern about potential duplicative charges to DG customers?

A. Rate No. 67 provides a standby service option to demand-metered customers with DG. Separate standard service is also available to demand-metered DG customers. The bases for Rate No. 67 are the production, transmission, and distribution costs for SPS to provide the standby capacity necessary for DG customers, and those costs are based upon the demand DG customers require from the SPS system rather than kWh. Rate No. 59 does not apply to demand-metered DG customers, with the exception of Irrigation customers. KWh-customers with DG, however, are not demand-metered. Since capacity costs are recovered through kWh energy charges applicable to kWh-metered customers, the kWh-based Rate No. 59 applies to the generation from DG installed on the service premises of kWh-metered DG customers.

Q. Please describe the types of "production, transmission, and distribution costs" Rate No. 67 recovers.

A. Rate No. 67 is intended to recover the same types of fixed capacity costs that Rate No. 59 recovers:

- the return on SPS's rate base;
- depreciation expense associated with SPS's production, transmission, distribution, and general plant;
- O&M expense associated with generating stations, T&D facilities, and other types of facilities;
- A&G expense, such as salaries, benefits, and insurance;
- capacity costs included in PPAs; and
- taxes, including both income tax and taxes other than income tax.

As noted above, Rate No. 59 originally applied to all customer classes with standby service. SPS introduced Rate No. 67 in Case No. 10-00395-UT to address concerns that Rate No. 59 resulted in duplicative recovery of demand-metered customers' capacity costs.