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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO STUDY FIXED COSTS OF PROVIDING ELECTRIC SERVICE TO CUSTOMERS	**CASE NO. IPC-E-18-16** **COMMENTS OF THE COMMISSION STAFF**

BACKGROUND

On May 9, 2018, the Commission ordered Idaho Power Company ("Company") to "...file a study with the Commission exploring fixed-cost recovery in basic charges and other rate design options prior to its next general rate case." Order No. 34046 at 31. The Commission also ordered the Company:

> to undertake a comprehensive customer fixed-cost analysis to determine the proper methodology and "spread" of fixed costs as they relate to the Company's customers. The Company, with input from interested parties, shall outline the scope of the study that should include exploring fixed-cost recovery in basic charges and other rate design options. A status update shall be filed with the Commission on a quarterly basis, with more specific deadlines prescribed in the coming notice of application in that matter.

Order No. 34046 at 23.

On Oct 19, 2018 the Company petitioned the Commission to initiate a docket in order to study fixed-cost recovery in basic charges and other rate design options as required by Order No. 34046. On Nov 9, 2018, the Commission issued Order No. 34190, Notice of Petition and

Notice of Intervention Deadline, which directed Staff to informally confer with parties about the procedural and substantive scope of the docket, proposed schedule, and other matters, and then report back to the Commission by April 30, 2019. Staff's report ("Staff's Report") included tables of rate designs and rate design attributes under consideration by parties at that time.

Intervening parties ("Intervenors" or "Parties") are Idaho Conservation League, Avista Corporation, NW Energy Coalition, Idahydro, Idaho Irrigation Pumpers Association, Inc., Rocky Mountain Power, Vote Solar, City of Boise City, Idaho Sierra Club, Idaho Clean Energy Association, Industrial Customers of Idaho Power, and Russell Schiermeier. Parties met for a total of one pre-settlement conference and five settlement meetings.

On August 9, 2019, the Company provided a draft copy of the Fixed Cost Report to Parties, requesting their feedback. The Company submitted its Fixed Cost Report to the Commission, along with a motion to accept this report, on September 30, 2019. The Company updated its Fixed Cost Report to correct some incorrect references on December 10, 2019.

STAFF ANALYSIS

Summary

After conducting a comprehensive review of the Company's Fixed Cost Report and supporting workpapers, Staff believes the Fixed Cost Report is incomplete and cannot be relied upon as a basis for changing rate designs. In particular:

- The evidence presented by the Company is insufficient to determine whether current ratemaking methods allow the Company to currently over-recover or under-recover all of the fixed costs authorized by the Commission;
- The Company did not provide sufficient evidence to support a change in rate design;
- Rather than undertaking a comprehensive customer fixed-cost analysis, the Company provided the Commission a position paper advocating its preferred rate design; and
- The Company did not adequately consider input from Parties regarding the scope of the report. The Company should have heeded Parties' input and provided a much more comprehensive and quantitative analysis of rates design options.

Introduction

Staff believes the Company's Fixed Cost Recovery Report should have given more attention to the topic of fixed cost recovery and the options for fixed cost recovery. Instead, the Company's Fixed Cost Report focuses on the proportion of revenue recovered from each class through the Company's preferred billing mechanisms: Customer Charges, Demand Charges, and Energy Charges. Nowhere in its Fixed Cost Report does the Company provide any quantitative information showing whether or not it is adequately collecting its fixed costs, either through its base tariff rates, or through riders such as the Fixed Cost Adjustment ("FCA") and Sales Based Adjustment Rates ("SBAR").

Staff explains the difference between revenue and fixed costs as follows. The costs of serving each class include variable costs, such as the costs of fuel and market purchases; and fixed costs, such as employee salaries, capital depreciation, debt service, and Commission authorized return on equity in capital investments. When the revenue recovered from a class through rates equals, or exceeds, the cost of serving that class, the Company will recover all of its fixed costs from that class. This is true, regardless of whether the revenue is recovered through Customer Charges, Demand Charges, or Energy Charges.

When the revenue recovered from a class is less than the cost of serving that class, then the Company may not fully recover the fixed costs of serving that class. Because the Company is obligated to pay for fuel, purchased power, and employee salaries, the inability to recover fixed costs first manifests itself as a Return on Equity ("ROE") that is less than that authorized by the Commission.

The Fixed Cost Report does not provide any quantitative comparison showing how alternative rate designs proposed by the Company would better collect the Company's fixed costs than current rate designs. In Staff's discussion of fixed cost recovery, Staff will provide a more in-depth discussion of the Company's ability to recover its fixed costs and will outline the analysis that should be conducted prior to considering alternative rate designs for adoption. Staff's fixed cost recovery section will also discuss the Company's ability to recover its fixed costs through basic rates and charges, as well as through riders, such as the Power Cost Adjustment ("PCA"), SBAR, and FCA mechanisms. Using evidence provided by the Company in its Fixed Cost Report and supporting work papers, Staff was unable to determine that the Company is either over-collecting or under-collecting its fixed costs.

The Company's Fixed Cost Report focuses narrowly on the use of rates to collect the Company's revenue requirement. Although Staff takes it as axiomatic that rates must allow the Company a fair opportunity to recover its revenue requirement, Staff notes that many different rate designs can achieve this goal. So long as rates afford the Company an opportunity to recover its revenue requirement, Staff believes that rates may be chosen to achieve other goals, such as energy efficiency, incenting customer behaviors that defer or avoid future plant investment, or allowing customers the ability to control their bills.

The Fixed Cost Report advocates a particular rate design that the Company refers to as "Cost of Service Informed," often to the exclusion of an objective and comprehensive analysis of other rate designs proposed by Parties. As shown in Attachment A, the Company either did not analyze, or did not adequately analyze, many of the rate designs proposed by Parties. Staff believes the Company should have conducted an objective and comprehensive analysis of all rate designs discussed instead of providing a position paper advocating for its preferred Cost of Service Informed rate design. Staff does not take a position on what, if any, changes should be made to the Company's current rate design; however, Staff believes that some rate designs warrant a more detailed analysis than was presented by the Company. Had the Company's Fixed Cost Report fully complied with the Commission's order, Staff believes that it could have served as a toolbox which could be referenced by the Commission, Staff, and other Parties when discussing the pros and cons of current rate designs, as well as rate designs that may be proposed to the Commission for consideration.

Staff disagrees that the Company's Cost of Service Informed rate designs are truly informed by Cost of Service. Under the Company's proposed Cost of Service Informed rate designs, the proportion of revenue collected through each rate component (Customer, Demand, Basic Load Charge, and Energy) is proportional to the Company's Class Cost of Service ("CCOS") allocators; however, the Company provided no evidence that its proposed billing determinants correspond to the Company's CCOS allocators. Despite the similar names, the correspondence between the Company's Demand charge and the Company's Demand CCOS allocators is weak. Of particular concern is the Company's inability to show how its proposed Basic Load Charge ("BLC") is related to factors that cause the Company to incur incremental fixed costs. Staff will discuss these concerns, as well as general Cost of Service principles, in its Cost of Service discussion.

Staff researched the experiences of other companies and jurisdictions with rate designs similar to those studied in the Company's report. Some of these experiences are informative. In the case of some rate designs, such as the Company's proposal to implement demand charges for Residential and Small General Service ("R&SGS") customers, Staff confirmed that no other investor-owned utility in the country has implemented a mandatory residential charge. Only one investor-owned utility, Westar, has implemented mandatory demand charges for solar customers. Importantly, the experiences of other jurisdictions can alert the Commission to potential unintended consequences of each rate design. Staff has summarized its research in the subsection discussing each rate design.

Cost of Service

The Company's last general rate case used a Cost of Service study based on 2010 calendar year data. IPC-E-11-08, Larkin di at 4. In order to provide a more up-to-date basis for its Fixed Cost Report, the Company developed an updated CCOS using calendar year 2017 information as its basis ("Straw Man CCOS"). The Straw Man CCOS was developed using the IPC-E-11-08 methodology, updated to account for changes such as the creation of Rate Schedules 6 and 8. Staff believes that the Straw Man CCOS is an appropriate basis for the current discussion about rate designs, but also notes that the 2017 calendar year information used to develop it has not been as thoroughly vetted as it would be in a formal rate case.

The Straw Man CCOS classifies costs as either customer-related, demand-related, or energy-related. Customer-classified costs are those costs that vary with the number of customers in the class, and include plant investments and expenses associated with meters, service drops, billing, and customer service. Because they can usually be associated with particular customers, the Company is able to directly allocate most of its customer-classified costs to individual classes. The Fixed Cost Report assumes all customer-related costs to be fixed. Fixed Cost Report at 57.

Demand-classified costs are incurred to serve customers' maximum loads. Because each piece of plant must be designed to meet the peak load placed on it, demand-related costs are closely related to measures of peak consumption such as Coincident Peak ("CP") and Non-Coincident Peak ("NCP") allocators.

As noted earlier, some distribution plant, such as meters and service drops, can be associated with particular customers and are classified as customer-related costs. Distribution plant that cannot be directly assigned to particular classes are allocated using a class NCP allocator. Fixed Cost Report at 64.

Because they must be designed to meet system-wide peak demand, the Company's transmission and generation plant are allocated using a variety of CP allocators.

In its Fixed Cost Report, Idaho Power assumes all Customer and Demand classified costs to be fixed, and that Energy classified costs are variable. Although this division is simple, Staff notes that a considerable amount of generation plant is classified as Energy, and thus, according to the Company's model are variable, and not fixed costs. In fact, the Company's Strawman CCOS considers 55.4% of fixed base load generation to be a variable energy cost, rather than a fixed cost. Fixed Cost Study at 22. In order to study the effects of classifying all generation base load plant as Demand, and thus as Fixed Costs, the Company developed CCOS No. 3. This scenario follows the same methodology as the Company's Straw Man CCOS but classifies all generation plant as Demand. Had the Company used CCOS Scenario No. 3 as the basis for the Fixed Cost Report, the reported fraction of fixed costs collected in the Company's energy charge would have been even larger than that reported by the Company. Fixed Cost Report at 23, Figure 13.

Staff notes that the allocation of a portion of fixed base load plant as an energy related expense is consistent with the methodology used to develop the Company's jurisdictional load factor. It is also consistent with the methodology prescribed in Order No. 30722 (IPC-E-08-10).

Energy classified expenses typically include the costs of fuel, energy purchases, and other variable expenses associated with the production, transmission, and distribution of energy; however, as noted previously, the Company's Strawman CCOS classifies a large fraction of its fixed base load generation plant as a variable energy expense. In fact, approximately 50% of the Energy-classified variable costs in the Company's report represent the fixed costs of base load generation plant. Fixed Cost Report at 22. Energy classified costs are allocated to customer classes using the normalized energy values for each class weighted by marginal energy costs. Fixed Cost Report at 64.

Use of Cost of Service in Rate Making

A Cost of Service study is an attempt to assign costs to each class according to the manner in which each class caused the Company to incur costs. The Cost of Service methodology employs hundreds of different formulae that may either represent industry best practice, Commission order, or the Company's best attempt to formulate a reasonable methodology. Each of the hundreds of formulae embodied in a Cost of Service study are based on assumptions that may only be approximately correct, or that may have changed since the methodology was adopted. For example, since the Company's last rate case (IPC-E-11-08), distributed generation systems have proliferated, and two new rate classes have been created; however, the Company's last rate case methodology did not include methods for valuing the contribution of distributed generation resources, or for determining the costs to serve those customers. In short, the Company's Cost of Service methodology is an evolving work-in-progress that is neither static nor perfect. The Company's Cost of Service Study may be a useful starting point, but the Commission is free to deviate from it when its application would lead to unfair, unjust, or unreasonable results. Thus, the results of a Cost of Service study do not necessarily represent an allocation of the Company's revenue requirement that the Commission believes to be fair, just, and reasonable.

The results of Cost of Service studies often are used to identify potential cost shifting from one class to another. For example, the Cost of Service model proposed by the Company in its last rate case allocated $127,619,827 to the Schedule 24 Agricultural Irrigation Class ("Irrigators"). IPC-E-11-08, Larkin di. Exhibit No. 38. However, the base revenue ultimately allocated to this class was only $107,383,256, or about 84% of the Company's Cost of Service Revenue Requirement. IPC-E-11-08, Motion for Approval of Stipulation, Exhibit No. 3. Viewed through the lens of the Company's Cost of Service model, there was a $20,236,571 cost shift from Irrigators to other parties; however, use of a different Cost of Service model could have given a very different result.

Once each class's revenue requirement has been determined, base rates for each class are determined in order to recover that class's revenue requirement. It is possible that the rate design developed for a particular class over-collects or under-collects revenue from that class; however, because revenue collection from one class has little or no bearing on the revenue collected from another class after each class' revenue requirement has been set, it is incorrect to say that this process results in a cost shift from one class to another. We can only say that the revenue collected from a particular class is either greater than, or less than, that authorized by the Commission.

Whereas the Cost of Service process aims to allocate costs to individual classes, rate design is intended to fairly collect revenue from individual customers in a way that is most beneficial to all customers. Cost of Service takes a retrospective look at how costs have been incurred, while rate design can be used to incent future behaviors that lower costs for all customers. For example, large volumetric energy charges incent behaviors that decrease energy consumption. In addition to incenting conservation of coal, natural gas, or hydro-resources, these rate designs can lead to lower average energy costs when marginal energy costs are high.

Likewise, time differentiated demand charges that incent reductions in demand at system CP or class NCP can help delay, or even avoid, future expenditures on generation, transmission, or distribution plant. At present, Schedules 9, 19, and 24, charge customers for demand through their Demand and/or Basic Load charges.

On page 28 of the Fixed Cost Report, the Company states "A demand charge sends an efficiency signal—one that correlates with load factor and encourages customers to reduce their peak energy usage." Staff believes that this statement is only partially correct. Although a demand charge does, indeed, signal customers to reduce their demand, it does not necessarily provide a signal that incents customers to reduce demand during the critical periods that drive Company investment in new capital. In order for a demand charge to effectively signal customers to reduce consumption during coincident and non-coincident peak periods, the demand charge would need to be time differentiated so that demand costs more during the Company's peaking periods.

For most classes, the correlation between the Demand charge and the CP allocator is weak. According to the Company, the Demand charge is intended to recover a portion of capacity-related costs associated with the generation and transmission of electricity. Fixed Cost Report at 7. A customer's demand charge is based on that customer's 15-minute peak consumption, regardless of whether that peak coincides with system coincident peak, or not, so there can be a mismatch between the coincident peak time and the time at which the customer's peak demand is assessed. This mismatch sends a poor economic signal to customers who could reduce or eliminate consumption during time periods corresponding to system CP.

For example, Schedule 24 secondary service irrigation customers pay an in-season demand charge of $6.98 per kW of demand. Most irrigation customers pump water 24 hours per day during much of the growing season, so even if irrigation customers were to reduce consumption during the Company's summer peaking period of 1:00 pm to 9:00 pm, they would still be assessed the same peak demand charge for using their pumps outside of the peaking period. This alone does not provide an incentive to reduce system peak demand to defer investment in resources to meet additional demand requirements.

The Basic Load Charge ("BLC") is another demand allocator that is intended to collect a portion of the capacity-related fixed costs of distribution facilities. Fixed Cost Report at 7. Depending on customer class, the BLC is calculated using either the customer's highest peak or using an average of the customer's highest peaks over the preceding twelve months. Fixed Cost Report at 7. As noted earlier, distribution costs are typically allocated across customer classes using an NCP allocator. Because the customer's peak consumption periods do not necessarily coincide with class NCP, the BLC does not send an economic signal that is effective at reducing class NCP.

In order to incent customers to reduce consumption during Non-Coincident-Peak periods, the BLC would need to be based on consumption that occurs during Non-Coincident-Peak periods used to develop the NCP allocator; however, Staff was unable to ascertain any relationship between the BLC and the Company's NCP allocators. In Production Request No. 7, Staff asked the Company to provide information that could correlate the timing of demands used to calculate customer BLCs with class NCPs. In its response, the Company stated that "The requested information is not available." The Company furthermore stated that, "Comparison between the dates and times of non-coincident peak and customer individual peaks would be based on different, unmatched data sets."

Prior to implementing any new BLC charges, Staff believes the Company should study the relationship between the BLC and the peaking events that drive the Company to incur costs.

Fixed Cost Collection

Staff found no evidence, either in the Fixed Cost Report or the accompanying work papers, that the Company is either over-collecting or under-collecting the fixed costs embedded in its Commission authorized revenue requirement. Given that the Commission ordered the Company to conduct a fixed cost analysis, Staff believes this to have been a serious omission.

Likewise, Staff believes the report should have analyzed the effect of the FCA and the PCA on the collection of fixed costs through proposed rate designs, as the parties agreed to regarding the scope of the report.

Basic rates are designed, using pro-forma test year information from the Company's last rate case, to recover all of the Company's fixed and variable costs. To the extent that customer usage, customer count, and weather varies from the pro-forma test year, the FCA is intended to ensure that the Company collects its authorized fixed costs.

Because the prices of fuel and purchased power can vary substantially from pricing assumed in the Company's pro-forma test year, the Commission has authorized the Power Cost Adjustment ("PCA") mechanism. The PCA allows the Company to properly recover its variable costs, as well as some fixed costs.

As noted in Staff's discussion of Cost of Service, some of the Company's fixed costs are classified as variable Energy Costs. Recovery of energy classified fixed costs is achieved using the Sales Based Adjustment Rate and is computed as part of the Company's PCA. The SBAR calculation in the PCA adjusts for either the under-recovery or over-recovery of energy-classified production cost recovered through base rates due to the difference between the amount of energy predicted to be consumed when base rates were set (total energy billing determinants) and the actual amount of energy consumed.

The Company's FCA and the SBAR component of the PCA exist to allow the Company to fully recover fixed costs not recovered in variable energy rates. As discussed below, it is possible that the current FCA allows the Company to over-collect its fixed costs; however, absent more complete information than was provided in the Company's Fixed Cost Report, it is not possible for Staff to determine whether the FCA is allowing the Company to over-collect or under-collect the fixed costs embedded in the Commission authorized revenue requirement.

Staff notes that the Company's current Fixed Cost Adjustment mechanism is intended to be a true-up mechanism that "decouples," or separates, billed energy sales from revenue in order to remove the financial disincentive that exists when the Company invests in Demand Side Management ("DSM") resources and activities. It is calculated as the difference between the level of fixed cost recovery authorized by the Commission in the Company's last general rate case, and the level of fixed cost recovery that the Company recovered through actual billed energy sales during the calendar year. The FCA is calculated using a Fixed Cost per Customer ("FCC") and Fixed Cost per Energy ("FCE") that are calculated during each rate case.

In the most recent general rate case (IPC-E-11-08), the residential FCC was calculated by dividing the fixed costs embedded in the Commission authorized residential revenue requirement ($258,560,620) by the number of residential customers in the Company's test year (397,403). The resulting FCC was $650.63 per customer. In its last FCA filing, the Company reported 445,452 residential customers.

The FCE represents the fixed costs embedded in the Company's volumetric rates. In the most recent general rate case (IPC-E-11-08) this was found to be $0.051602 per kWh.

Each year, the FCA is calculated by subtracting the product of the current year's billed kWh sales and the FCE from the product of the current year's customer count and the FCC. In 2017, the customer count was 426,737 residential customers, 48,000 more than when base rates were established, and the Company billed those customers for 4,731,973,170 kWh, so the FCA was $33,468,647.

Implicit in this calculation is the assumption that the fixed cost of serving new customers is the same as the fixed cost to serve the customers who existed at the time of the Company's last rate case. Neither the Fixed Cost Report nor the work papers provided with it allowed Staff to verify this assumption.

Staff had expected a more complete discussion of the need for and effects of revenue stabilization mechanisms such as the FCA and PCA with its analysis of all rate designs summarized in Staff's April 30, 2019 report. Instead, the Company states, without supporting evidence, that, "Many of the cost of service methodologies and rate designs in this report, if implemented, would impact the level of reliance on existing FCA (either up or down) or warrant consideration of a modified fixed cost recovery mechanism." IPC-E-18-16 Fixed Cost Report page 2. The Company's report continues to restate this last assertion – that even with these rate designs included in the Study, the FCA, in one form or another, would still need to be considered.

Staff has repeatedly expressed concerns with the current FCA mechanism. The amount the Company recovers fluctuates yearly as a function of the kW sales and the number of customers. The annual recovery amount for the FCA deferral is never "trued up" to the actual yearly or current costs of the Company, and Staff has not audited said fixed costs of the Company for comparison purposes to what the FCA is recovering. Nor does the FCA currently tie back to the Company's DSM portfolio or savings.

Since its inception in 2007, the FCA has collected $180,565,737 from R&SGS customers. During the 12 years that the FCA (2007-2018) has been in effect, Residential customers have received surcharges in all years except one. Small General Service customers have received additional surcharges in every year since the FCA's inception. Between 2013, the first year for which complete data is available, and 2018, $137,964,362 has been collected from customers taking service under R&SGS tariffs. Over the same 6 years, the average calculated

Fixed Cost Recovery amount (FCE x kW sales) was $275,720,994, compared to the $258,560,620 level of fixed costs authorized by the Commission in the last general rate case (IPC-E-11-08). The difference between what the FCA methodology calculates and the authorized level of fixed costs authorized in the last general rate case has not been audited by Staff, nor has the change in fixed costs been deemed prudent by the Commission, yet the Company recovers the additional revenue each year through the FCA. Staff expected that the influences of the FCA and the PCA on fixed costs collected by the Company would be studied in the Company's report. Staff also notes that the Company has not been in for a general rate case since IPC-E-11-08 was closed. If the Company were under-collecting its fixed costs, Staff surmises that the Company would have filed a new rate case. At minimum, the Company should have explained how updating its rates through a rate case could have corrected over-recovery/under-recovery due to long term changes in customer counts or load.

Selected Rate Designs

Staff's April 20, 2019 report to the Commission summarized the rate designs and attributes that were being discussed by parties at that time. Few of these rate designs and attributes were analyzed and discussed in the Company's report. In this section, Staff will discuss selected rate designs and describe analyses that should have been included in the Company's Fixed Cost Report.

Staff will begin with a discussion of three rate designs that will serve as book-ends for understanding more complicated rate designs: A rate design with large volumetric rate, a rate design with a large fixed charge, and a rate design with a large demand charge. Because the Company's current R&SGS schedules already rely on large volumetric rates, Staff's discussion of large volumetric rate designs also serves as a discussion of the Company's current R&SGS rate designs. Staff's discussion of the other two end-points, a structure with a large fixed charge and a structure with a large demand charge, will serve as reference points for discussions about the pros and cons of more complicated, multi-part rate designs.

Staff notes that any rate design that incents changes in customer behavior is likely to be destabilizing and may lead to improper collection of the Company's fixed costs. For example, we would expect the current R&SGS rate designs, with their large volumetric rate components, to incent decreased electric consumption. Given the 1.3% average annual decline in residential energy consumption reported by the Company, it appears that these rate designs are working as expected; however, in decreasing consumption, this rate design also results in decreased collection of the fixed costs embedded in volumetric rates. Fixed Cost Report at 29. Similarly, we would expect a rate design with a large demand component to incent reductions in demand, which would lead to decreased collection of the fixed charges embedded in the demand charge, and lead to the same potential for under-recovery that exists for volumetric charges. As discussed previously, the FCA is intended to offset the potential for over/under-recovered revenue in volumetric rates. If the Company were to introduce a demand charge, it is quite possible that the Company would need an FCA-like mechanism to offset the potential for under-recovered revenue in its demand rates.

As discussed earlier, rate designs may be used to incent behaviors that benefit all customers. When marginal energy costs are high, reduced consumption benefits all customers by lowering the average cost of energy embedded in volumetric rates, and reductions in demand benefit all customers by deferring or avoiding the costs of new production and transmission plant needed to meet demand. Staff cautions, however, that the number of goals that can be achieved with rate design is zero-sum. For example, an increased demand charge will require a decreased volumetric charge, thereby diluting the volumetric charge's ability to signal reduced volumetric consumption.

Attributes of Large Volumetric Rate designs:

The Company's Residential and Small General Service rate schedules rely on large volumetric rates. Using the Company's 2017 Straw Man CCOS as a guide, Staff found that 94.1% of the revenue collected from these classes is collected through the volumetric component of these schedules' two part rate designs. The remaining revenue is collected from a small, five dollar monthly customer charge. Using information from the 2017 Straw Man CCOS, Staff determined that under the Company's current rate schedule, R&SGS customers paid an average volumetric charge of $0.084 per kWh.

About 46% of Company sales are to the Company's R&SGS classes, so it is important to understand how well volumetric rates fare in collecting the fixed costs allocated to these classes. According to the Company's 2017 Straw Man CCOS, the revenue requirement allocated to the R&SGS classes was $455,596,645; however, the revenue collected from these classes, $475,435,592, exceeded this allocation by 4.4%. Company Response to Staff's Production Request Nos. 21-24. Because the revenue from these classes exceeds the R&SGS revenue requirement, Staff notes that the Company fully recovered its fixed costs from these classes in 2017.

One drawback of using rate designs with a large volumetric component is their sensitivity to annual and seasonal variations in weather. A standard rate case practice is to adjust test year revenue for the effects of weather ("Weather Normalization"). Without Weather Normalization, it is not possible to determine whether the current R&SGS rate design systematically over-collects fixed costs, or whether fixed-cost over-collection in 2017 was a one-time occurrence. Staff believes that the Company should have conducted a more thorough analysis to determine whether or not the Company's R&SGS rate designs consistently over-collect or under-collect fixed costs.

As noted in Staff's discussion of the Company's Cost of Service models, the Straw Man CCOS classifies more than half of its base load plant as energy. Under this methodology, the energy classified cost per kWh for R&SGS customers is $0.030 per kWh. When all base load plant is classified as demand (CCOS Scenario 3), the energy classified cost drops to $0.016 per kWh. Depending on whether fixed costs are viewed through the lens of the Straw Man CCOS or CCOS Scenario 3, the fixed costs embedded in the residential volumetric rate are either $0.054 per kWh, or $0.068 per kWh. Under either Cost of Service methodology, fixed costs account for the majority of costs embedded in the R&SGS volumetric rates.

Because large volumetric rates provide an incentive to reduce consumption, it is not surprising that monthly per-capita energy consumption is decreasing. If energy conservation is a goal, then the 1.3% annual decrease in per-customer residential energy use reported by the Company is a feature, and not a defect of the R&SGS rate schedules. Staff included a partial analysis of fixed cost recovery through the Company's current rate design in its Fixed Cost Collection discussion; however, given the information provided in the Company's Fixed Cost Report, Staff is unable to completely quantify the impact that decreased energy consumption has on the Company's ability to collect its fixed costs in basic rates. Staff believes that the Company's Fixed Cost Report should have quantified the impact of decreased volumetric sales on fixed cost recovery.

A second benefit of large volumetric rates is their effect on peak demand. Because measures undertaken by customers to reduce overall consumption usually reduce peak consumption, reduction in energy consumption is often accompanied by concomitant reductions in system peak load. For example, air conditioning is a primary driver of summer peak demand.

Because it is likely that an air conditioning unit will be operating during summer coincident peaking events, use of more efficient air conditioners reduces both total energy use and peak demand. It is likely that much of the 1% annual reduction in demand reported by the Company is due to measures undertaken by customers whose primary aim was reducing their monthly energy bill.

A rate design employing large volumetric rates may not fairly reflect the way that individual customers cause the Company to incur costs. For example, the infrastructure required to connect a single-family residence to the system is approximately the same, regardless of whether that residence is heated using an electric furnace or a gas furnace. Because electrically heated homes use much more energy during the winter months, they pay much higher energy charges than their gas heated counterparts, and because fixed costs are embedded in volumetric rates, customers with electrically heated homes pay a larger share of the Company's infrastructure costs, even though they require about the same amount of infrastructure as other customers.

Currently, the residential schedule employs a tiered rate design: Monthly energy rates increase with increasing consumption. One effect of this structure is to destabilize revenue collection through volumetric rates and exaggerate the effects of weather on revenue collection. Another effect is to increase the fraction of the Company's fixed costs paid by customers with electrically heated homes. The Company briefly discusses this issue on pages 26-27 of its Fixed Cost report.

Staff's investigation found that nearly all investor owned utilities use volumetric rates for residential customers, though some commissions have approved time-based volumetric rates as a method for reducing demand and potentially deferring the need to invest in new plant.

Attributes of Rate Schedules with increased Fixed Charges

As noted in Staff's Cost of Service discussion, most of the costs that the Company incurs serving its customers are fixed. Using the Company's Straw Man CCOS as a guide, Staff determined that of the total $987 annual cost of serving R&SGS customers, about $654 (66.3%) represents fixed costs. If the production plant costs are classified as demand (CCOS Scenario 3), fixed costs represent $812 (82.3%) of the annual costs of serving the Company's R&SGS customers. Given the large fraction of fixed costs embedded in customer bills, Staff believes that rate designs with high fixed cost components deserve some consideration.

The Company briefly discusses a rate design with a high fixed charge on page 27 of the Fixed Cost Report but dismisses it because it does not promote other policy objectives. Although a rate design with a large monthly fixed charge would not promote energy conservation or demand reduction, it would stabilize and reduce bills for most customers who rely on electricity to heat their homes. This could be particularly important for some low income or fixed income customers.

For the current discussion, Staff will use the Company's 2017 Straw Man CCOS as the basis for a 2-part residential rate design with a $56 monthly customer charge reflecting the fixed costs of serving residential customers, and an energy charge of $0.030 per kWh ("Hypothetical Fixed Rate"). Staff notes that the average cost of serving a residential customer is about $85 per month. Given that average residential consumption is 957 kWh per month, the Company would collect an average energy charge of $29 per month, enabling the Company to collect the entire $85 average monthly cost of serving its residential customers. Because the $0.030 per kWh energy charge represents only variable energy costs incurred by the Company, the Company should be able to collect its fixed costs regardless of variations in consumption due to variable weather or changes in customer behavior.

In order to understand how adopting the Hypothetical Fixed Rate would impact its customers, Staff examined the billing effects on three hypothetical residential customers: An average Idaho Power residential customer with consumption of 11,485 kWh per year, a customer with electrical space heating and consumption of 22,270 kWh per year, and an apartment dweller with gas heat, and electrical consumption of 4,550 kWh per year.

Under the Hypothetical Fixed Rate, the average Idaho Power customer would see no change in average monthly bills relative to the current volumetric rate design. Her average monthly bill would remain at approximately $85 per month; however, she would not see as much seasonal variation in her bills under the Hypothetical Fixed Rate design as she does under the Company's current volumetric rate design.

Residential customers with electrical space heating would see the largest changes to their monthly bills. Under current rates, the typical residential customer with electrical space heating pays an average bill of $152.40 per month, with a January bill of $323.09 per month. Under Staff's Hypothetical Fixed Rate, the same customer's average monthly bill would drop to $107.39 per month, with a January bill of just $162.41.

The apartment dweller's average monthly bill would increase from \$33.24 per month to \$66.50 per month under the Hypothetical Fixed Rate design.

Staff's investigation of other investor-owned utilities found that none charged a monthly fixed charge as high as the \$56 Hypothetical Fixed Rate. Idaho Power's \$5 service charge for residential customers is relatively low compared to the residential service charges of most other investor-owned utilities. Staff's review found that in 2017, the fixed charges approved by Commissions ranged from \$5 to \$20 per month, with an average fixed charge of \$11.19.

Demand Based Rate designs

A properly structured demand charge can incent customer behaviors that allow the Company to reduce, defer, or avoid investment in new production, transmission, or distribution plant; however, because demand classified plant-in-service represent costs that have already been incurred by the Company, a reduction in customer demand does not result in an immediate reduction in Company expenses. Furthermore, because properly structured demand charges can be expected to result in demand reduction over time, they would not be expected to stabilize fixed cost recovery. Currently, residential customers pay no demand charge, yet residential demand is still decreasing at a rate of 1% per year. This is only slightly less than the 1.3% annual decrease in residential energy consumption. If the Company were to implement a residential demand charge, it is not unreasonable to expect that demand could decrease at a much greater rate than it currently does. Staff believes the Fixed Cost Report should have included a much more thorough analysis of how increasing demand charges could result in decreased demand, and a concomitant reduction in fixed costs collected through demand charges.

Several of the Company's rate schedules employ one or more demand charges. We will use the Schedule 9 Primary Large General Service rate schedule to illustrate how demand charges are used. In addition to a \$285 monthly service charge and an average energy charge of about \$0.043 per kWh, Schedule 9 Primary customers pay three different demand-related charges: A Demand Charge, an On-Peak Demand charge, and a Basic Load Charge.

The Demand Charge is based on the average kW power supplied during the 15-consecutive minute period of maximum use, regardless of the time of day that this peak occurs. Currently, Schedule 9 Primary Service demand charges are \$5.09 in the summer, and \$4.46 in the winter. This demand charge will incent customers to reduce their peak demand, but not the time of day at which peak demand occurs. According to the Company's Fixed Cost Report, the

Demand Charge is intended to recover a portion of capacity-related generation and transmission costs; however, as noted in Staff's discussion on Cost of Service, transmission and generation costs are driven by a need to meet system coincident peak demand. Given that the demand charge is the same, without regard to whether or not the Customer's peak consumption is coincident with system peaking events, it is difficult to see how the current demand charge is related to the way in which customer classes cause the Company to incur costs, or how it fully incents customers to avoid consumption patterns that drive the need for investment in production and transmission plant.

The Schedule 9 Primary Service On-Peak Billing Demand Charge is a $0.95 per kW charge assessed during the 15-minute period of maximum use during the On-Peak time period[1]. This small charge provides a weak signal to Schedule 9 customers that incents reduced demand during likely peaking hours.

Schedule 9 Primary Service customers also pay a $1.28 per kW Basic Load Charge ("BLC"). According to the Company, this charge recovers a portion of capacity-related fixed costs of distribution facilities, such as substations, primary lines, and transformers. Fixed Cost Report at 7. For Schedule 9 customers, the charge is assessed monthly, and it is based on the average of the two highest monthly billing demands over the past year. As noted in Staff's Cost-of-Service discussion, distribution plant is typically allocated based on each class's non-coincident peak. Because the peaks used to compute a customer's BLC do not generally coincide with class non-coincident peak, Staff does not believe that the BLC provides a particularly good signal to customers to engage in consumption patterns that decrease the need for distribution plant. In Production Request No. 7, Staff asked the Company to explain how the peaks used to calculate the BLC coincide with the Class Non-Coincident Peak Period used in the 2017 Straw Man CCOS. In its response, the Company stated, "Comparison between the dates and times of non-coincident peak and customer individual peaks would be based on different, unmatched data sets."

There do not appear to be any investor-owned utilities in the country with mandatory demand charges for non-solar residential customers. However, several investor-owned utilities offer pilot programs or other optional tariffs that include demand charges.

[1] The Company's On-Peak Billing Period occurs from 1:00 pm to 9:00 pm, Monday through Friday (except holidays) from June through August.

Attributes of Time of Demand Based Rate Designs

As noted in the previous section, the Company's demand charges do not fully incent reduced consumption during critical time periods such as system CP and class NCP. A time differentiated demand charge sends a signal that encourages customers to both decrease peak loads, and to shift the times at which their peak loads occur. The relatively small Schedule 9 On-Peak Billing demand charge is a Time of Demand charge. Of course, a larger On-Peak demand charge could provide a larger incentive to reduce consumption during system CP.

The Company's Schedule 24 Irrigation Tariff provides a good example for why such a rate design might be desirable. During the irrigation season (May through September), Irrigators who receive power at secondary level voltage pay a $22.00 monthly service charge, an energy charge of approximately $0.0562 per kWh, and a $6.97 per kW demand charge. This demand charge is the same, regardless of the time of day that the Irrigator's peak occurs. Most Irrigators can, and do, pump water 24 hours per day during the irrigation season. Without an appropriate economic signal, there is no incentive for Irrigators to reduce pumping during hours of likely system coincident peak. Staff notes that secondary level irrigation customers account for approximately 23% of summer peak demand, so any reduction in Irrigator's demand could help defer the need for future generation and transmission plant. Company's Straw Man CCOS.

Currently, Irrigators can sign-up for the Company's Optional Schedule 23, peak rewards program. Under this program, Irrigators can receive a bill credit of $5.00 per kWh in exchange for allowing the Company to curtail their power during system peaking events. A time differentiated demand charge could incent all Irrigators to reduce their demand during periods of time corresponding to system coincident peak.

It is important that the peak period used to calculate the On-Peak billing charge correspond with the time periods during which a system coincident peaking event is likely to occur. Currently, the On-Peak billing period used in the Company's tariffs is defined as 1:00 pm to 9:00 pm, Monday through Friday. In Appendix H, the Company presents the results of an analysis showing that most peaks occur between 3:00 pm and 10:00 pm, rather than the 1:00 pm to 9:00 pm summer On-Peak period currently used in the Company's Tariffs.

There do not appear to be any investor-owned utility in the country with mandatory time-of-demand charges.

Time of Use Rate Designs

In its discussion of Volumetric Rate designs, Staff noted that in addition to incenting reductions in energy consumption, volumetric rates were probably responsible for some of the 1% annual reduction in demand reported by the Company. The incentive for decreasing CP and NCP demand can be increased by increasing volumetric rates at times coinciding with periods during which system coincident peak, or class non-coincident peak are likely to occur. The Company's discussion of Time of Use rate designs includes a discussion of two different rate designs. The first is actually a hybrid rate design that includes both time differentiated energy rates and a Basic Load Charge.

The second is a more traditional Time of Use ("TOU") rate design. The Company criticizes the TOU rate design because it "does not reflect the cost to serve." Fixed Cost Report at 34. Staff both disagrees with this assessment and disagrees that it is necessary for a rate design to be based on the Company's preferred collection mechanism in order to reflect a "cost to serve." By increasing volumetric charges during potential peaking periods, TOU rate designs signal customers to reduce consumption during times when cost to serve is the highest. Furthermore, because the Company's Demand and BLC charges are calculated without regard for timing of the Customer's peak, there is little relationship between these charges and the CP and NCP allocators used to allocate Demand classified costs, so it is difficult to see how the Company's proposed Demand and BLC charges are relevant to Cost of Service. In short, Staff believes that a traditional Time of Use rate design is a more effective signal of cost causation than the Company's proposed Demand and BLC charges.

The California Public Utilities Commission instituted mandatory Time of Use rates for all commercial, industrial, and agricultural customers under its jurisdiction. Residential customers have the option to enroll.

The Company's Cost of Service Informed Rate Designs

The Company proposes a number of rate design modifications that it claims to be Cost of Service Informed. In order for a rate design to be truly Cost of Service informed, it is necessary for the rate design's billing determinants to be correlated with the allocators used to assign a share of the Company's revenue requirement to each rate class. An example can be found on page 45 of the Fixed Cost Report, where the Company proposes introduction of a Basic Load Charge for Irrigators. Currently, Irrigators pay a single demand charge each month. The proposed Basic Load Charge would be calculated using the average of the previous 12 months' two highest monthly demands. Fixed Cost Report at 42. Given that most Irrigators' load profiles are relatively flat throughout the growing season, it is difficult to see how introducing a new demand charge that is nothing more than an average obtained from the existing demand charge is an improvement. For irrigation customers, the proposed BLC does nothing that can't be accomplished by increasing the demand charge with a corresponding decrease in volumetric rates. Given that the proposed new charge does not provide an incentive for customers to reduce load at system peak, it is difficult to understand the purpose of the proposed Basic Load Charge.

The Company also proposes what it calls a Three Part Demand Structure for residential customers. Staff notes that the Company's Three Part Demand Structure actually uses four components: A fixed $17.28 Customer Charge that corresponds with customer-classified charges; a $5.41 per kW on-peak demand charge corresponding with summer production related costs; a $1.15 per kW Basic Load Charge corresponding with distribution-related costs, and a tiered energy charge that would include all energy costs, all transmission costs, and non-summer production costs. Fixed Cost Report at 28 - 31 and 79.

As currently configured, the Company's residential AMI meters are not capable of measuring peak demand during specified time periods; however, the meters are capable of recording each hour's consumption. As a proxy for on-peak demand, the Company proposes using the maximum hourly consumption during the Peak Billing Period (3:00 pm to 10:00 pm during summer weekdays) as a proxy. Company's response to Staff's Production Request No. 9. Staff believes that this proposed demand charge can incent reduced coincident peak demand, thereby deferring investment in production plant; however, this reduction will also result in reduced revenue collected through the Demand charge. Prior to considering the introduction of a demand charge into the Company's residential rates, Staff believes it to be imperative that the Company look at how customers might use both short and long-term measures to reduce demand. Many customers will be able to achieve meaningful short-term demand reductions by assuring that certain appliances, such as air conditioners, clothes dryers, or hair dryers, are not used during the on-peak period. Over the longer term, when opting to replace existing appliances, customers may choose smaller appliances, such as smaller air conditioning units, with reduced consumption and demand.

Staff is also concerned with the Company's proposed Basic Load Charge, primarily because the Company was unable to demonstrate how it is correlated with either residential class non-coincident peaking events or with customer behaviors that decrease the need for future production plant. Company Response to Staff's Production Request No. 7. Staff believes that the following quote from James Tong, and former FERC commissioner Jon Wellinghoff encapsulates the problems of using demand charges to recover the sunk costs of distribution plant:

> Furthermore, the only things that utilities size according to demand from individual residential customers are the final line transformers and connecting secondary lines. These costs are small relative to those of generation and transmission capacity. And most of these capacity costs are sunk. By definition, sunk costs cannot be incremental. Using the cost-causation principle to justify demand charges to pay for sunk costs makes no sense; future usage behavior does not cause costs that have been sunk.

Tong and Wellinghoff, Utilities Dive, October 2016.

As previously stated, no other investor owned utility in the country has implemented a mandatory three-part residential rate that includes a demand component for non-solar customers.

Rate Design for Net-Metering Customers

In Order No. 34509, the Commission ordered the Company to conduct a credible and fair study of the costs and benefits of net metering. In particular, the Commission specified several ways in which the study must reflect public input, including public workshops and the ability for customers to provide comments during the study design and study review phases. Staff recommends that rate design changes for net metering customers be discussed in these public workshops in order to hear and incorporate public feedback.

SUMMARY AND RECOMMENDATIONS

Summary

The Company's Fixed Cost Report is incomplete and cannot be relied upon as a basis to reasonably change rate structures. In particular:

- The evidence presented by the Company is insufficient to determine whether current ratemaking methods allow the Company to over-recover or under-recover all of the fixed costs authorized by the Commission;
- The Company did not provide sufficient evidence to support a change in rate design;

- Rather than providing the Commission with a toolbox that it could use when assessing various rate designs, the Company provided the Commission a position paper advocating its preferred rate design; and
- The Company did not adequately consider input from parties regarding the scope of the report. The Company should have heeded Parties' input and provided a much more comprehensive and quantitative analysis of rates design options.

Recommendations

Prior to any proceeding that contemplates a change in rate design, the Company should perform an objective and comprehensive study of all rate designs under consideration. The study should consider the pros and cons of each rate design, including:

- A quantitative analysis of each rate design's ability to collect fixed costs embedded in the Commission's authorized revenue requirement;
- A quantitative analysis of the rate design's stability under conditions of changing weather, increased customer counts, or changes in customer behavior;
- A quantitative analysis of the impacts of revenue stabilization mechanisms (e.g. FCA, PCA, and SBAR) on the rate design's ability to collect fixed costs; and
- A quantitative and qualitative analysis that changes in rate design may have on disparate groups within the affected classes.

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Ed Jewell

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i:umisc/comments/ipce18.16ejmmklsdemerfsd comments

Comparison of Company's Fixed Cost Report with the rate designs and attributes presented in Staff's April 30th, 2019 report to the Commission

		Rate Designs								
Attribute		Company's Current	Single Fixed Charge	Volumetric Charge Only	Demand Charge Only	Time Differentiated Rate	Time Differentiated Demand	Time of Use, both Energy and Demand	Connected Load Based Charge	Peak Rewards
Impact on Fixed Cost Recovery	Revenue Stability	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed
	Credit Risk	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed
	Relationship with PCA/FCA		Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed
	Ability to Recover Fixed Costs		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
	Impact on Future Cost Causation	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed
Billing Impacts to Customers	Impact Across Class		Not Discussed	Not Discussed	Not Discussed		Not Discussed	Not Discussed	Not Discussed	Not Discussed
	Low Income Impact		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
	Stability for Customers		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
	Gradualism	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed

(Cont.) Comparison of Company's Fixed Cost Report with the rate designs and attributes presented in Staff's April 30th, 2019 report to the Commission.

		Rate Designs								
Attribute		Company's Current	Single Fixed Charge	Volumetric Charge Only	Demand Charge Only	Time Differentiated Rate	Time Differentiated Demand	Time of Use, both Energy and Demand	Connected Load Based Charge	Peak Rewards
Price Signalling and Behavior	Conservation	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed
	Controllability		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
	Peak Reduction or Other Methods to Decrease Need to Invest		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
	Predictability	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed
	Simplicity		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
Fair Just and Reasonable	Fairness of the Specific Rates in Costs		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
	Undue Discrimination		Not Discussed	Not Discussed	Not Discussed		Not Discussed		Not Discussed	Not Discussed
Other Considerations	Implementation Costs	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed	Not Discussed

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 21st DAY OF JANUARY 2020, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-18-16, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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