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January 21, 2020

Idaho Public Utilities Commission
11331 W Chinden Blvd
Suite 201-a
Boise, ID 83714

Reference: CASE NO. IPC-E-18-16 - IN THE MATTER OF THE PETITION OF IDAHO POWER COMPANY TO STUDY FIXED COSTS OF PROVIDING ELECTRIC SERVICE TO CUSTOMERS

Subject: Comments regarding Idaho Power Company's motion to accept Fixed Cost Report

Dear Commissioners:

In the attachment to this letter please find the Idaho Sierra Club comments regarding the subject Motion to accept the Fixed Cost Report Idaho Power submitted.

Sierra Club has intervened in the referenced case and has actively participated in settlement conferences. We ask that you keep in mind the time and attention Commission Staff, Sierra Club and multiple other intervening parties spent in settlement conferences related to the referenced case as you review our comments.

For reasons detailed in the attached, Sierra Club asserts Idaho Power Company's Fixed Cost Report does not satisfy the requirements of a "comprehensive customer fixed-cost analysis" (Order 34190 p1) and should not be accepted in its current form.

Sincerely,

Michael Heckler

Michael Heckler
Chair, Energy Committee
Idaho Sierra Club

Cc: Zack Waterman

Attachment: Sierra Club comments – IPC-E-18-16 Fixed Cost Report

Sierra Club Fixed Cost Report comments – Table of Contents

1 SUMMARY OF COMMENTS..2

2 TOO NARROW A PERSPECTIVE..3

3 VOLUMETRIC CHARGES AND CONTROLLING COST GROWTH..................6
- 3.1 Fixing a non-problem (6)
- 3.2 Revenue predictability vs Controlling Cost growth (7)

4 ACCOUNTING CONVENTIONS..9
- 4.1 Peak load definition & Generation Capacity cost avoidance (9)
- 4.2 Growing summer load drives costs (10)

5 THE BIG DOLLAR ISSUES..13
- 5.1 Residential class – it's where the money is (13)
- 5.2 The "Elephant in the Room" (14)
- 5.3 A look at 12CP vs "Scenario 1" (15)

6 RATE DESIGN SOLUTIONS..18
- 6.1 TOU rates for the Irrigation class (18)
- 6.2 TOU rates for the Residential class (20)

7 CONCLUSION AND REQUESTED REMEDY..22

LIST OF FIGURES AND TABLES

Figure 1	Two views of Revenue and Fixed Costs (3)
Figure 2	Two views of accounting convention impacts (4)
Figure 3	Customer Sales this Century (8)
Figure 4	Frequency and timing of peak system loads (10)
Figure 5	Summer peak load growth = 1.2GWs (11)
Figure 6	Declining asset utilization (11)
Figure 7	Residential = big money (13)
Figure 8	Irrigators under-charged by $44 million (15)
Figure 9	Above Average Use Pattern (15)
Figure 10	12CP vs Scenario 1 allocations (15)
Figure 11	Scenario 1 increases Irrigation demand cost (19)
Figure 12	Cost categories for Irrigation customer class (19)
Figure 13	Residential class peak summer loads are growing fast (21)
Figure 14	Class load patterns on peak load days (21)
Table 1	Summer peak expansion (12)
Table 2	Class Revenue & Cost for Classes without Demand Charges (14)

1 SUMMARY OF COMMENTS

After reviewing the Fixed Cost Report Idaho Power submitted (the Report), Sierra Club feels compelled to provide comments which can be briefly summarized as:

1. The Report, as submitted, more closely resembles a sales pitch for rate designs that decrease the portion of revenues derived from the quantity of kilowatt-hours sold than it does a "comprehensive study".
2. The Report offers a large-scale, theoretical solution without establishing that the solution will solve more than a relatively minor problem.
3. The Report's emphasis on dramatically lowering the use of volumetric charges precludes effective use of price signaling to customers that could control cost growth and in so doing provide benefits for all Idaho Power customers.
4. In preparing the Report, Idaho Power used accounting methods in their analyses that are either outdated or insufficiently focused for the problems being analyzed.
5. The report effectively ignores the largest dollar value fixed cost issues within their customer base and the effects these cost issues have on <u>Residential</u> and <u>Irrigation</u> class rate design alternatives.
6. Time of use (<u>TOU</u>) rate design options for the Residential and Irrigation customer classes, that could address several fixed cost issues, were not fairly evaluated in the Report.
7. Due to multiple substantive deficiencies within the Report, the Commission should not grant Idaho Power's request that the Report be accepted in its current form.

The Report fails to provide key analyses. Rising Residential class air conditioning load is driving Idaho Power fixed cost growth. Use of an out-of-date cost allocation method produces a big subsidy in favor of the Irrigation class. Innovative TOU rates, if analyzed fairly using contemporary cost of service data, could address both issues. Sierra Club views Idaho Power's failure to fairly address these matters as fatal deficiencies in the Report they submitted.

Detail explaining how Sierra Club arrived at these conclusions is provided on the pages below.

2 TOO NARROW A PERSPECTIVE

The Report shows in great detail how variable costs allocated to each customer class align with volumetric components of various rate designs[1]. The Report's narrow focus on this one aspect of fixed cost recovery serves Idaho Power's interests. But it does so at the expense of a fair review of rate designs that serve the public interest.

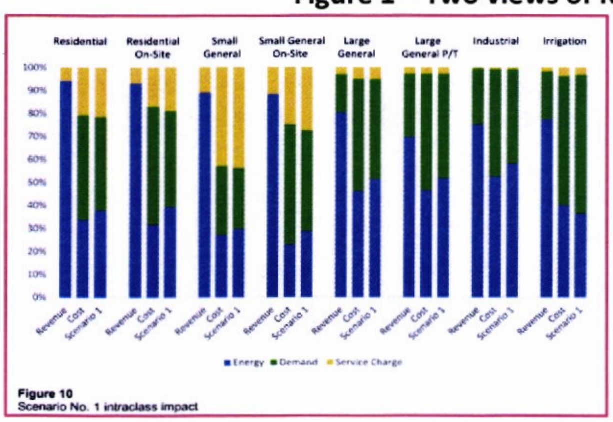
Sierra Club believes the Report offers too little attention to rate designs that control future fixed cost growth. The Report is not a "comprehensive study". As written, the Report does not adequately inform future Commission decisions regarding rate design.

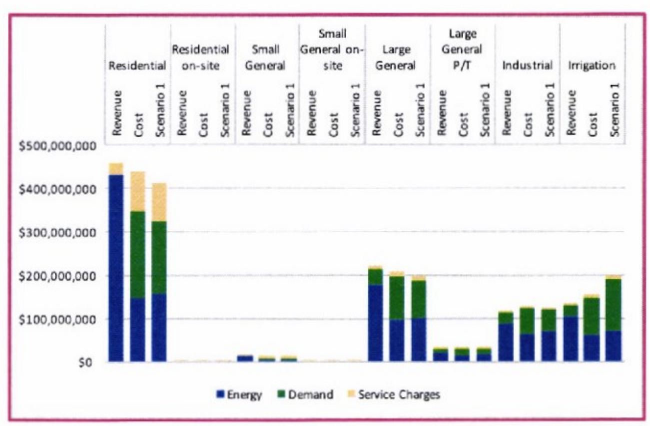
Magnitudes more informative than percentages - In the majority of Figures within the Report, Idaho Power displays data in a normalized format, displaying the composition of data (as percentages relative to 100% for each class) rather than the actual customer class' dollar values.

Sierra Club acknowledges the need for fair treatment of all customer classes and for comparisons across customer classes. But using a percentage-based form of normalization disguises the magnitude of variations between classes. And in doing so, hides relevant information and distracts from opportunities to control future cost growth.

Figures 1 & 2 demonstrate the difference between percentages and dollar magnitude. In each Figure both charts are based on the same data. Collectively they document opportunities for controlling future fixed cost growth in two customer classes: Residential and Irrigation.

Figure 1 – Two views of Revenue and Fixed Costs





[1] *"A side-by-side comparison for each customer class for the existing rate design revenue collection proportions ("Revenue" column) versus the fixed and variable proportions informed by the most recent cost of service methodology ("Cost" column) is provided ... to indicate how close or far any class's revenue collection proportions are to the current underlying cost structures."* Report P1

The chart on the left, taken from the Report[2],focuses on how revenue is collected through volumetric charges. The chart on the right, or one analogous to it, does not appear in the Report. While the chart on the right shows the relative magnitude of how revenues and costs are spread *across* customer classes, the Report chart focuses on the composition of costs *within* each class. The chart on the right demonstrates the degree to which the Company is recovering the costs allocated to the class, the Idaho Power chart does not.

Viewing data through the lens of charts such as the one on the left are emphasized throughout the Report and inappropriately asserted to be indicators of the effectiveness of a rate design. Analyses indicating the magnitude of revenue and cost spreads across classes and how rate designs affect those spreads are given short shrift.

Calculating revenue requirements - There are multiple approaches to cost allocations across classes. In Figure 2 the charts are based on the same data. Both show each class' required revenue amount under two different accounting methods for distributing certain fixed costs. But as used in the chart shown on the left in Figure 2 below, normalization hides the fact that different cost allocation methods dramatically change class revenue requirements.

In the chart on the left, the difference between the height of the green and gold bars in the chart represents different amount of revenue requirements calculated for each class under two different accounting methods. In that chart on the left that difference for the Irrigation class appears to be about twice as large (although opposite in sign) as the difference for the Small General on-site class.

The chart on the right shows a dramatically different view based on the exact same data. On the right, we see that use of the "Scenario 1" accounting method would estimate the revenue required to be collected from the Small General on-site class to be a little over <u>$4.4 thousand lower</u> than the estimate produced by the traditional (Cost) accounting method from the 1980s. The analogous difference for the Irrigation class is not twice as big as left chart implies, but <u>1,000 times larger</u>. The "Scenario 1" accounting method suggests that Irrigation class required revenue is <u>$44 million higher</u> than the amount computed using the traditional accounting method.

Figure 2 – Two views of accounting convention impacts

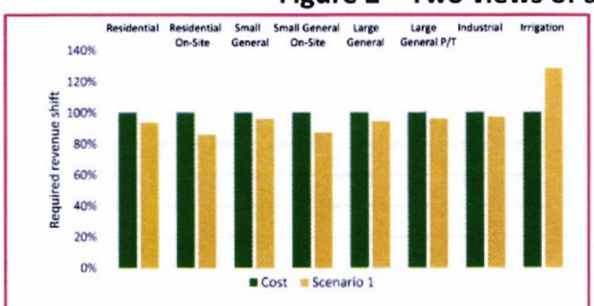
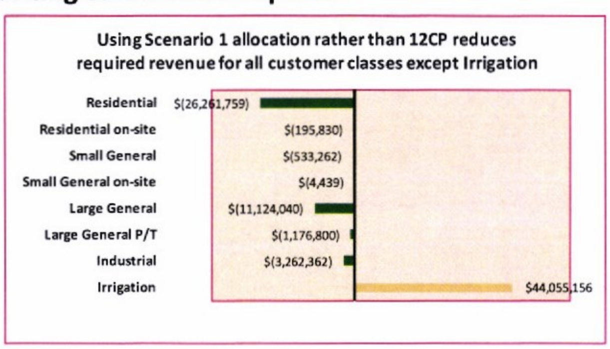


Figure 9
Scenario No. 1 interclass impact—required revenue



[2] Report p19

An outdated allocation structure - Most all of the cost analysis in the report is based on the outdated "Cost" allocation structure. That allocation structure was designed to address issues related to spreading the fixed costs from new coal plants added in the 1970s. The fixed costs Idaho Power now incurs arise from dramatically different customer use of the system compared to the usage patterns behind the cost causation methodology developed in the 1980s. Today Idaho Power has different:

1. Seasonal load – back in the 1980s, in some years load peaked in the winter, other years the peak was in the summer[3]. Today, however, the Company's system peaks always occur in the summer and are 25% higher than winter peaks.
2. Interruptible load – back in the 1980s Astaris (FMC) was a very large, but Interruptible part of total system load. That interruptability allowed FMC load to be used to clip peaks while filling load in other months. While Idaho Power currently has an excellent Irrigation demand response program, Irrigation load does not "fill up" load in the Spring and Fall periods like FMC did.
3. Meter reading – back in the 1980s customer load data was manually collected. For efficient use of the labor needed to visit each customer's meter, usage data was only available on a monthly basis. AMI changes our ability to see usage on an hourly rather than monthly basis so we can focus on the hours when peak loading occurs, not just the months.

Inadequate representation of public and parties' interests - In April, the Commission staff reported that discussion between Idaho Power and intervening parties was "vigorous"[4]. Sierra Club believes (and we expect other intervenors would concur) that highly relevant points were raised in the multiple "settlement" discussions. For example, the Staff Report reflects a study design in which five rate attribute categories would be systematically considered. Those attribute categories represent interests important to the Company as well as the public interest in reducing the need for future fixed costs growths. The Report submitted by Idaho Power has not fairly addressed the issues intervenors raised during this docket.

We believe there are rate designs, especially time of use (TOU) rates for the Residential and Irrigation customer classes, that provide substantial opportunities for controlling future fixed cost growth. We believe the Commission asked for a comprehensive study and instead have received a narrow Report backward focused on sunk costs and fatally deficient in reviewing forward price signals. As further detailed in Section 6, when TOU rates were reviewed, Idaho Power used self-serving accounting conventions in developing the rates and a grossly superficial analysis to dismiss them.

This docket is not a rate case. Intervening parties presented relevant cost allocation alternatives that support a dramatically different analysis of rate designs such as TOU. Those alternatives

[3] *"Idaho Power continues to be a dual-peaking (summer and winter) system"* Order 21365, 1987, p 10
[4] See Staff report dated April 30, 2019

are not adequately reviewed in the Report. Fair analyses of TOU rates should be included in any comprehensive study of rate designs and the spread of fixed costs.

3 VOLUMETRIC CHARGES AND CONTROLLING COST GROWTH

Sierra Club views the Report, as written, as a narrow justification for raising fixed charges to customers. While the rate designs Idaho Power favors could serve Company interests by making revenue growth more consistent and predictable, there is no showing that the Company currently faces a problem meeting its revenue requirements. More insidiously, by narrowly focusing on ways to improve the timing of recovery of costs associated with the Company's prior investments, the Report does not objectively or adequately evaluate rate designs that control future cost growth, dismisses rate design alternatives that more accurately reflect contemporary cost to serve, and ignores huge cross-customer class subsidies.

It was always going to be risky for the Commission to ask a party with specific commercial interests to develop a study that provides an objective toolkit of rate options for the Commission to consider. Using the intervenor process to inject diverse party interests into the Report was tried, but the report Idaho Power has produced does not do service to the inputs that various parties provided in multiple "settlement" discussions. The Report addresses Idaho Power interests but is critically deficient in addressing public interests.

3.1 Fixing a non-problem

If Idaho Power were operating in a part of the country with declining electric demand or under a Commission that didn't allow annual fixed cost recovery adjustments they could have legitimate reason for focusing rate design reviews narrowly on fixed cost recovery. But in Idaho there is substantial load growth and an existing cost adjustment mechanism.

FCA is messy but effective – In the report, Idaho Power promotes rate designs that increase the portion of revenues collected via fixed charges rate components and reduce the portion collected via volumetric components. They assert that such alignment improves fairness and balances policy objectives.[5] Frequently within the Report, Idaho Power suggests a preference for reduced reliance on an FCA[6].

We concede that rate recovery is important, but the Company has made no showing that they face any recovery deficiency. If the Company did face a significant challenge meeting its revenue requirement one could possibly see a more pressing need for raising fixed payments and reducing volumetric revenues. But in Idaho we have a fixed cost adjustment mechanism.

Of course, determining exactly which charges should be included in the FCA is messy process. And the FCA imposes a workload on Commission staff and the Company. But the FCA is an effective solution to the problem of annual variations in system sales and Idaho Power's preference for rate designs that reduce reliance on the FCA imposes disproportionate restrictions on the fair review of other rate design options.

No prospect of declining electric demand in the Idaho Power service territory - All recent IRPs forecast continued volumetric load growth over the next two decades. In fact, if a carbon tax were to be imposed at some time in the future, electric load migrating from previously lower cost natural gas space and water heating plus added load from transport electrification might mean that future loads growth is under-estimated.

Idaho Power faces rising volumes of sales and corresponding opportunities for the increasing kilowatt-hour sales to adequately absorb fixed costs.

3.2 Revenue predictability vs Controlling Cost growth

Wall Street rewards Companies with consistent earnings (bottom line) and revenue (top line) growth. Getting a larger portion of its annual revenue moved from variable energy sales and into more constant and predictable fixed charges would help make Idaho Power's top line growth more consistent. Given that incentive structure, promoting rate structures based on how well they serve in making revenue streams more predictable is a logical approach for the Company. Within the Report, rationales for rate recovery have morphed into improved revenue predictability solutions.

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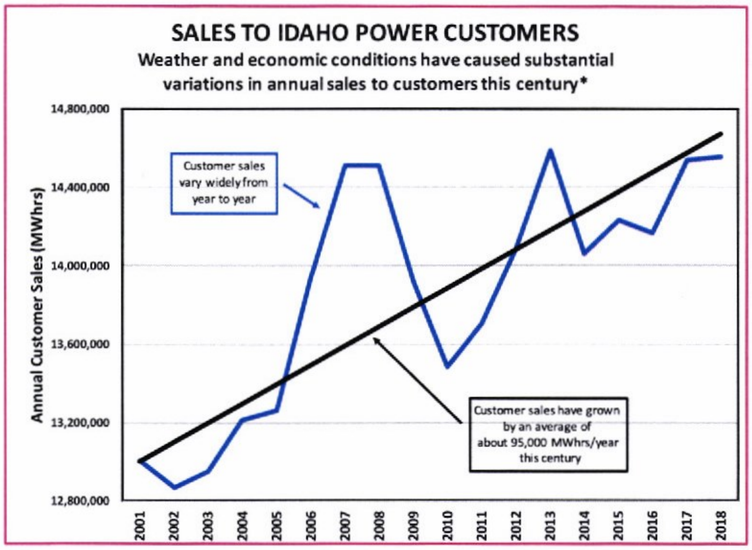
[5] *"The rate design evaluation presented in this Report includes an assessment of the extent to which each rate design option may provide for recovery of fixed costs in a manner that aligns with the underlying cost structure, improves fairness in the assignment of costs to individual customers and appropriately balances a range of policy objectives".* Report P3

[6] For example, see - *Continuing to apply the Schedule 1 and 7 rate designs (where the majority of fixed costs have been collected through a volumetric rate) to customers who are able to offset their consumption may not provide an opportunity to recover the classes' fixed costs absent a mechanism like the FCA* *Report p 39*

The rate designs presented in this report, if implemented, would impact the level of reliance on the existing FCA (either up or down) or may warrant consideration of a modified fixed cost recovery mechanism *Report p 27.*

Figure 3 – Customer Sales this Century[7]



As Figure 3 to the right displays, although energy sales have grown on average by about 95 million kilowatt-hours/year during this century, variations in weather and economic conditions do cause substantial variability from year to year in total kilowatt-hours sold to customers.

The service customers receive (heating, cooling, pumping, etc.) does vary with seasonal temps. But a fair review of rate designs should address more than policy questions on how best to deal with the inherent variability in the demand for the Company's services.

<u>Rate designs that improve revenue stability for the Company impose a high cost on the public's interest. In addition to meeting the need for recovery of required revenues, Bonbright and others agree that rate designs should also provide efficient forward-looking price signals, equitable cost allocation and assist in meeting policy goals. Idaho Power's emphasis on dramatically lowering the use of volumetric charges precludes potential use of price signals to customers that could control cost growth and assist in meeting policy goals to the benefit of all Idaho Power customers.</u>

[7] Data from the year 2000 are omitted to avoid confusion related to loss of FMC load starting in 2001

4 ACCOUNTING CONVENTIONS

To appropriately evaluate rate design alternatives that fairly and efficiently control future cost growth while addressing changing customer preferences, Sierra Club believes two substantive accounting issues need to be addressed.

One issue concerns the appropriate review of the time of day when peak loads are incurred and how the hour-range of those peak loads affects TOU rate design analysis. The other concerns how seasonality in load patterns affect fixed costs allocations to consumption in different months of the year. Both require changes to the analyses presented in the Report.

4.1 Peak load definition & Generation Capacity cost avoidance

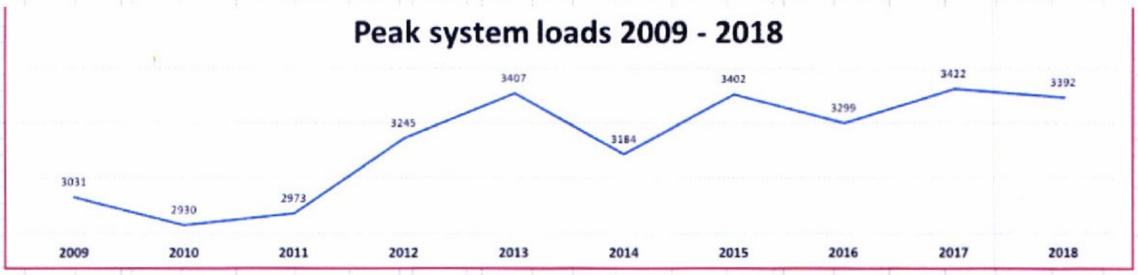
To control future costs, one needs to determine what events will cause that cost to be incurred. One type of potentially avoidable costs is associated with needing additional peak generation[8] to meet projected peak load growth.

Reliability and Cost avoidance warrant different analyses – Sierra Club acknowledges that reliability (as approximated by a Loss of Load Expectation (LOLE) analysis) is an important element of concern. The LOLE analysis Idaho Power used in the Report is based on hours when loads were within 340MWs of the historic system peak level[9]. The LOLE review found a total of 207 such hours. That set of 207 hours represents an overly broad range of the hours that are relevant to any peaking generation avoidance review. In the most recent 2019 IRP the marginal peaking generation resource was a group of three reciprocating engine powered generators with a capacity of about 55MWs. As figure 4 shows, over the past decade less than 30 hours of load have been within that 55MW range and those hours occurred starting at 2pm and ending at 8pm. The same dataset used in Figure 4 also shows that the earliest date for such a load occurrence was June 29th and the latest was on August 10th.

[8] Note that in the 2017 and 2019 IRPs a **$ Quarter billion** expenditure on B2H in 2026 was at least partially justified as being needed to meet a peak load capacity requirement

[9] *"Over the cycle of a day the Company chose an hourly reading that was 90 percent or greater than the peak hour as a proxy for "peak level" demand on the system. ...stated above it was found that 207 hours of the year would fall under the scope of 90 percent of the peak value for the day these results helped inform the recommendation to define the summer on-peak period of 3 p.m. to l0 p.m. during weekdays" Report p 77*

Figure 4 – Frequency and timing of peak system loads



2009, 2010, 2011, 2012 and 2014 did not have any hours when load was within 5% of the all-time system peak. Hours during 2013, 2015, 2016, 2017 and 2018 within 5% of all time peak load are listed below.

TOP 101 all-time LOAD HOURS

Hour ending	>95%	>96%	>97%	>98%	>99%	Totals
2pm	3	3				6
3pm			3	2		5
4pm	8	1	1		4	14
5pm	5	4	3	2	3	17
6pm	5	4	3	5	2	19
7pm	5	2	6	3	3	19
8pm	6	3	1	5		15
9pm	4	2				6
Totals	36	19	17	17	12	101

COLOR CODE

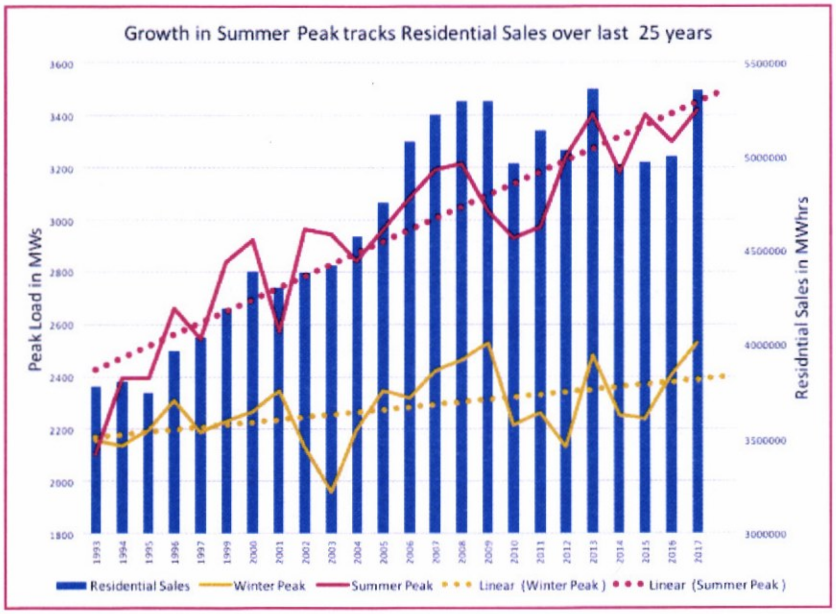
-	=	NOT within top 5% hours
3250-3284	=	Within 5% of all time peak load
3285-3319	=	Within 4% of all time peak load
3320-3354	=	Within 3% of all time peak load
3355-3389	=	Within 2% of all time peak load
3390-3422	=	Within 1% of all time peak load
Peak load	=	All-time system peak load

If we were to conservatively expand the timeframe when system peak loads might be expected to include all non-Holiday weekdays in the summer months of June, July and August (which averages out to 65.3 days/year) and multiple those 65.3 days by the 6 hours per day to cover the 2pm to 8pm period, we come up with a total of about 392 hours each year when an all-time peak load may be expected to occur. That calculation will be important in Section 6 when reviewing TOU rate analyses.

4.2 Growing summer loads drive costs

Growing air conditioning load, largely within the Residential customer class, combined with existing seasonal Irrigation load has changed Idaho Power resource requirements. As Figure 5 below shows, summer peak loads have exploded leading to the declines in asset utilization displayed in Figure 6. Table 1 shows that rather than mitigating, we can expect these trends to deepen over the next two decades absent some measures to control the associated cost growth.

Figure 5 – Summer peak load growth = 1.2GWs



Both Figures 5 & 6 reflect data from 1993 onwards. The 1993 start date was chosen because that was the last year when Idaho Power's winter load exceeded its summer load.

Figure 5 to the right shows that over the last 25 years Idaho Power has had a small average increase in the size of its peak winter load of about 250MWs, (see gold solid and dotted lines) while its average peak summer load has grown by about 1,200 MWs (see red solid and dotted lines).

The growth in summer peak closely matches growth in annual sales to Residential customers, which are represented by the blue bars in Figure 5.

Figure 6 – Declining asset utilization

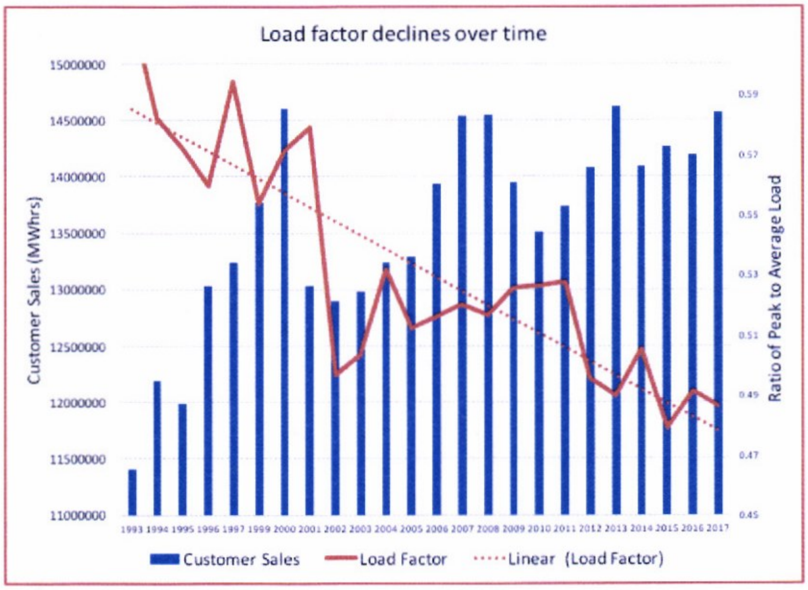


Figure 6 shows how peak load growth has outpaced average annual load growth over that same 25-year period.

The blue bars in Figure 6 represent total customer sales. Note the loss of the FMC load in 2021. In this chart, the solid and dashed lines show how total system load factor has declined. Declining load factors imply that more fixed costs need to be collected for each unit of energy sold.

Summer peak load growth outpacing increases in annual sales, with its inherent reduction in asset utilization is expected to continue into the foreseeable future.

As Table 1 displays, recent IRPs project summer peak loads growing faster than overall annual energy sales for the next twenty years.

Table 1 – Summer peak expansion

IRP Vintage	Projected peak load growth rate	Projected annual average load growth rate
2015	**1.2%**	**1.2%**
2017	**1.4%**	**0.9%**
2019	**1.2%**	**1.0%**

Sierra Club believes there are alternative approaches to rate design that address the rising peak - declining average load factor issue. Rate designs that provide customers with efficient pricing signals can be useful for controlling fixed cost growth associated with summer peak loads. We do not believe the Report fairly addresses those alternatives.

5 THE BIG DOLLAR ISSUES

Sierra Club acknowledges the importance of fair treatment for all customers and all customer classes. We have actively participated in the open dockets associated with Residential, Small General and Irrigation customers with on-site generation. Getting costs and benefits right for all customers, even those who fall into small dollar customer classes, is important. Nevertheless, those on-site generation customer classes currently involve very small percentages of Idaho Power's revenue requirement.

In any study of rate design options there are some really big dollar issues. Residential and Irrigation customer classes account for about 60% of the Idaho jurisdictional revenue requirement. Both have seasonal load patterns that contribute to Idaho Power's peak system load. Rate designs focused on each deserve a more detailed review than the Report provides.

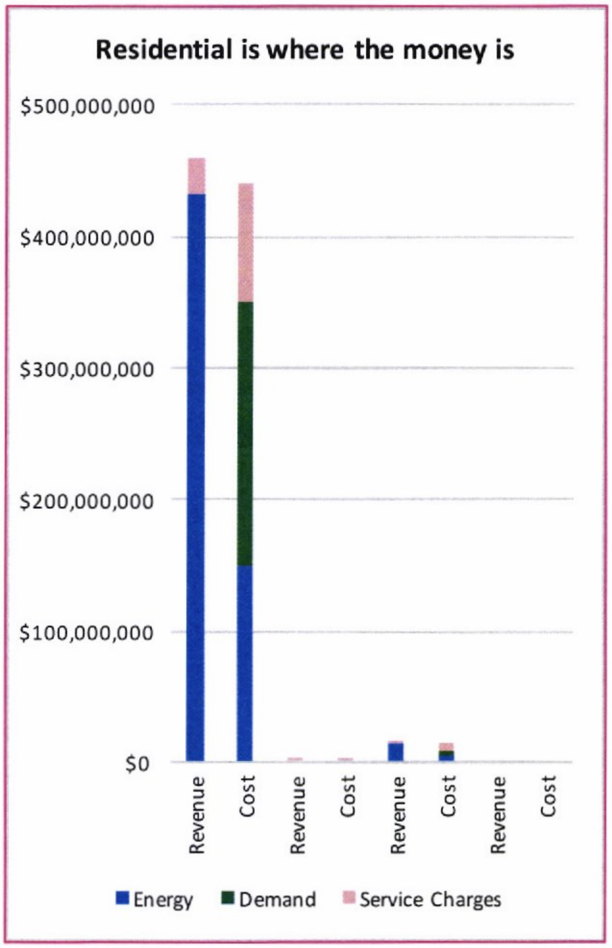
5.1 Residential class – it's where the money is

More of Idaho Power's revenues come from Residential customers than from any other customer class so it is not surprising that within the Report Idaho Power states:

> *"Because the energy rate is the primary component for collection of fixed costs related to generation, transmission, and distribution, the recovery of fixed costs per customer declines with any reduction in net energy usage and increases when net energy usage is greater than expected. With this relationship in mind, the company believes that these two classes (RESIDENTIAL AND SMALL GENERAL SERVICE) should receive the highest priority when considering rate design modifications."*[10]

Sierra Club largely agrees with the conclusion that rate design modifications for the Residential class should receive the highest priority of review. The Residential class is where the big money is.

Figure 7 – Residential = big money



The Residential, Residential with on-site generation, Small General and Small General with on-site generation customer classes do NOT currently

[10] Report p26

have demand charges. With the concern Idaho Power has expressed in reducing collection of fixed costs via volumetric rates, it is not surprising that a primary concern of the Company in this report is focused on those four classes. As Figure 7 and Table 2 demonstrate, 97% of the total revenues the Company receives from all four classes comes from just the Residential class.

Table 2 – Class Revenue & Cost for Classes without Demand Charges

Residential	Revenue	$ 458,833,395
	Cost	$ 439,504,152
Residential on-site	Revenue	$ 983,286
	Cost	$ 1,434,219
Small General	Revenue	$ 15,601,237
	Cost	$ 14,622,960
Small General on-	Revenue	$ 17,674
	Cost	$ 35,353

Sierra Club believes Residential customer load does drive a large portion of fixed cost growth. We believe that currently and for the foreseeable future, fixed cost growth will be tied to the volume and timing of energy demanded on the hottest summer days. Controlling future fixed cost growth will be better accomplished by providing price signals tied to these highest load periods, not by increasing the portion of Residential revenue collected in fixed payments.

5.2 The "Elephant in the Room"

Idaho Power first introduced the idea of spreading some of the costs of generation assets across all 12 months in a rate case filed in November, 1981[11]. The same issues were reviewed in an Idaho Power rate case (U-1006-265) later that decade. In one of the Orders associated with the -265 case the Commission stated:

> "We recognize that the subsidy which is implicit in the irrigation rate has elements of economic inefficiency. See testimony of Swan, Tr. pp. 781-789. Nonetheless, it is reasonable and fair in this circumstance for electric rate decisions to be influenced by other economic and equitable considerations. Those engaged in farming and many residential customers have suffered several years of hardship. Given the importance of the farm economy to the State of Idaho, it is appropriate to allow some rate "leniency." We hope that this will make some contribution toward the recovery of the industry, an economic consideration not a stranger to our decision making."[12]

Sierra Club is in no way seeking to harm the central role that irrigated agriculture plays in Idaho's economy. On the contrary, we are pleased with Idaho Power's clean by 2045 goal and, as further described below, see a key role in that transition is for irrigators that to use solar energy to produce both biological products and electric power.

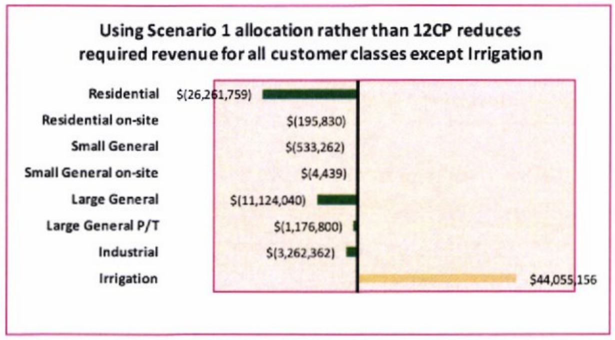
But we are not in the 1980s anymore. Subsidies that the Commission knowingly granted to the Irrigators during the "Farm Aid" period of severe economic distress in agriculture deserve review in any comprehensive rate design study. This docket is not about a rate case, it is about studying rate design alternatives. And a comprehensive study requires a look at how to deal with the biggest inter-class subsidy of all, the "Elephant in the Room".

[11] See Order 17856, final Order in -185 p 6

[12] Order No. 21365 July 1, 1987 at pages 48 - 49

5.3 A look at 12CP vs "Scenario 1"

Figure 8 – Irrigators under-charged by $44 million



As Sierra Club sees the issue, continued use of an obsolete accounting convention, called 12CP, "justifies" an unrealistically low estimate of the revenue requirement for the Irrigation class. Using the outdated 12CP cost allocation method has allowed the "inefficiencies" the Commission mentioned in Order 21365 to grow and metastasize.

When class revenue requirements are calculated, use of the 12CP seasonal cost allocation method provides cross class subsidies in the tens of millions of dollars (see Figure 8 above). It does this by over-estimating the cost caused by load in the Spring, Fall and to a lesser extent Winter seasons and substantially under-estimating costs caused by loads during the summer months when the Company experiences its system peaks.

12CP is no longer accurate - When developed back in 1981, 12CP sought to fix a problem that arose from the new coal plants Idaho Power had recently brought online. The coal plants had dramatically higher costs than the hydro resources they supplemented. A new approach was needed to allocate those high coal plant costs. 12CP was a way to spread those costs over all months. Since the new coal plants provided "baseload" power that would be used in all months, 12CP spread a portion of generation fixed costs more or less equally across all months of the year. The portion of generation costs spread in this way, called "intermediate load", was associated with service provided during hours when load was above the annual average level.

Figure 9 - Above Average Use Pattern

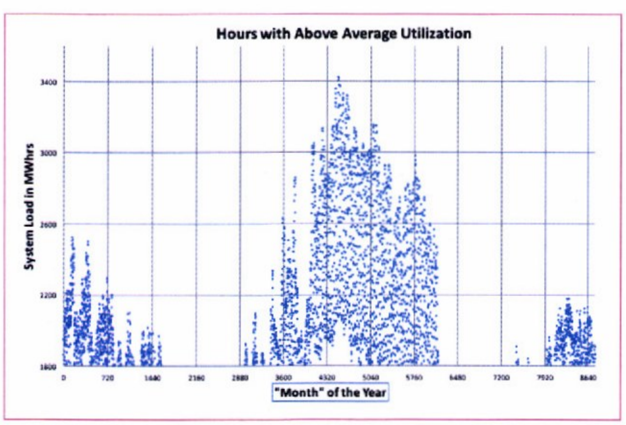
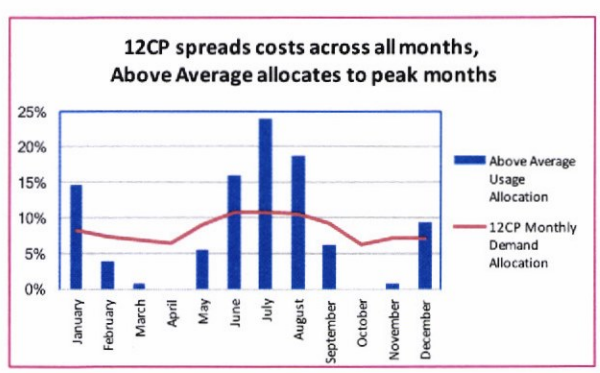


Figure 10 – 12CP vs Scenario 1 allocations



An illustration of the months when the "above average" usage currently occurs is shown in Figure 9. You can see that now most of the above average hours occur in the summer period. Almost none of this "intermediate" load occurs in March, April, October or November.

Figure 10 shows cost allocations across months and seasons. The gold line displays how the costs associated with "intermediate" generation assets are spread across months when using the 12CP method. The blue bars in Figure 10 show how those same costs would be allocated under the "above average" method, also known as "Scenario 1".

If a customer class has a very high annual load factor, they are largely unaffected by which allocation method is used because the higher revenue requirement they would incur in some months is offset by lower charges in other months.

But for low load factor customer classes with most of its consumption during the summer months the Scenario 1 allocation dramatically increases their revenue requirement. As displayed in Figure 8 above, updating the old 12CP cost allocation method to reflect current consumption patterns reduces required revenue estimates for all classes except Irrigation.

Idaho Power's customer load was very different back in the 1980s. Calculating the cost to serve customers (CCOS) based on a 12CP accounting convention from the 1980s ignores the evolution of Idaho Power's customer base over last four decades.

- Idaho Power's load now has a huge summer seasonal bias.
- There is no longer a big FMC interruptible load for clipping peaks and filling load in other months.
- AMI changes our ability to see usage on hourly rather than monthly basis so we can focus on the hours when peak loading occurs.
- The Company is moving out of the coal plants that sparked 12CP and considering new power generation options.

Scenario 1 explained - Sierra Club believes a comprehensive study of fixed cost "spread" requires, at least, a fair review of modifications to the 12CP allocation convention. To that end, the party supporting Scenario 1 modifications suggested four easily modeled changes in the cost of service study. Two were minor corrections to cost classifications with minimal dollar impact. The other two were changes in cost allocations with more substantive impacts[13].

[13] The relative impacts of the four modifications are displayed in Appendix E. They show that the vast of the inter-class impacts are associated with Mod "3" which looks at allocating "intermediate" load generation costs across months in a manner that reflects current seasonal load patterns.

1. **Bulk Transmission** - One of the allocation changes involved the bulk transmission cost allocation. Historically there were substantial cost advantages associated building large scale coal fired generating facilities even if these facilities were located far from the loads they served. Reasoning that many of the costs associated with bulk transmission are incurred to transport power from these remote coal plants to the load they serve, one request was made to change the bulk transmission allocation from 100% into Demand to 50% Energy / 50% Demand. This was presented as a relatively simple change for Idaho Power to model as the Company already uses this 50/50 allocation when evaluating its Oregon jurisdictional load. The effect of this change is to shift a modest amount of costs from low load factor customers to higher load factor customer classes.

2. **Seasonality** - The second allocation change involves generation costs associated with serving hours when loads are above the annual average load level. Traditionally these "intermediate"[14] load costs were allocated across all 12 months in proportion to each month's maximum load (called the 12CP method). The alternative Scenario 1 allocation spread those same costs but in proportion to the months when those "above average" loads currently occur. This change was proposed as relatively easy for Idaho Power to model and much more reflective how costs are currently caused, four decades after 12CP was invented. The effect of this change is to shift costs to summer peak load periods.

Sierra Club believes the cost of serving summer loads today (and for the foreseeable future) is substantially more expensive than it was back in 1981 when the 12CP allocation method was developed. We think allocating some of the fixed costs associated with generation and bulk transmission under the "Scenario 1" methods are much more closely aligned with current cost causation than the antiquated 12CP method[15].

Using Scenario 1 does suggests cross class subsidies to the Irrigation class are in excess of $40 million per year. That $40 million figure is a politically sensitive sum. But this docket is a study, not a rate case. And as presented below, even if Irrigators were faced with meeting a much higher revenue requirement, there are combinations of rate designs and new technology that could be harnessed to the benefit of Irrigators, all Idaho Power customers and the Idaho economy generally. These rate design alternatives deserve a fair review that the Report has denied them.

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[14] Idaho Power suggests that peak load generation charges are already adequately charge summer months. They ignore the fact that, as displayed in Figures 9, 60% or more of the "intermediate" load hours occur in the three summer months.

[15] Idaho Power's rebuttal to this argument ignores the seasonal aspects of cost causation and focuses on the narrow issue of alignment of fixed costs with fixed price rate components – *"While the modifications proposed through Scenario No. 1 ("Scenario 1" column) materially changed the costs allocation to customer classes / revenue spread, the impact to the development of the class-specific cost structures (as depicted in Figure 10) was relatively minimal. Therefore, the assessment of the effectiveness of fixed cost collected through the fixed components of the existing rate design for all customer classes is only slightly improved under this modification".* Report p19

6 RATE DESIGN SOLUTIONS

In a very recent presentation, the Regulatory Assistance Project (RAP) succinctly described a linkage between customer behavior, system costs and rate design that bears repeating here:

> ***"Rate designs should make the choices the customer makes to minimize their own bill consistent with the choices they would make to minimize system costs."***[16]

In the Report Idaho Power acknowledges that TOU based demand charges can send price signals that encourage more efficient system utilization.[17]

Sierra Club believes TOU rate designs reflect shared system costs better than any type of demand charges and deserved a much more fulsome review than Idaho Power provided in the Report. Demand charges were devised before widespread interval metering was feasible. AMI technology facilitates a new approach to demand charges. It is time for the investments made in AMI technology in Idaho Power's service territory to be put to higher use.

6.1 TOU rates for the Irrigation class

Sierra Club is concerned that TOU rates for Irrigators were not adequately reviewed in the Report. Idaho Power did mention that -

> *One party suggested an alternate rate design could be developed such that if an Irrigator did not take service during these 3-4 (peak load) hours then the customer would receive no demand charges for that month.*[18]

However, further down in the same paragraph the Company explains that it did not study this TOU type rate design because doing so would require a change to the cost of service method to ensure adequate fixed cost collection.

As explained under the heading "Fixing a non-problem" in Section 3.1 above, we do not believe Idaho Power has demonstrated that adequate fixed cost recovery has been a problematic issue for the Company. With the rapid growth in its service territory, increasing energy sales will continue to be adequate to collect the fixed costs associated with the Company's historic fixed cost expenditures. Sierra Club believes that the projected growth within Idaho Power's service territory suggests a need to focus on rate designs that could be used to control future fixed cost growth.

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[16] RAP – Demand Charges: The traditional Answer to the Wrong Question. Dec 20, 2019 p10

[17] **Demand Charges** – "Demand charges (both TOU and seasonal/monthly) were evaluated for all customer classes. Demand charges can send a price signal to customers that encourages a more efficient utilization of system capacity, however it is important to recognize collecting fixed costs through a volumetric charge may impact the company's ability to ensure fixed cost recovery." Report P25

[18] Report p 46

Sierra Club believes that a TOU rate structure for Irrigation customers can provide an excellent opportunity for Irrigation customers to minimize their bill for demand charges in a way that minimizes total system costs.

As shown in Figure 11 below, use of the Scenario 1 cost allocation method moves more "intermediate load" generation costs into the summer months (when those resources are used most heavily). This dramatically increases the amount of "Demand" charges allocated to Irrigation customers compared to Demand charge allocated under the historic 12CP "Cost" method. Figure 12 shows the increase in allocated Demand costs amount to more than $33million.

Figure 11 – Scenario 1 increases Irrigation Demand costs (see Appendix G)

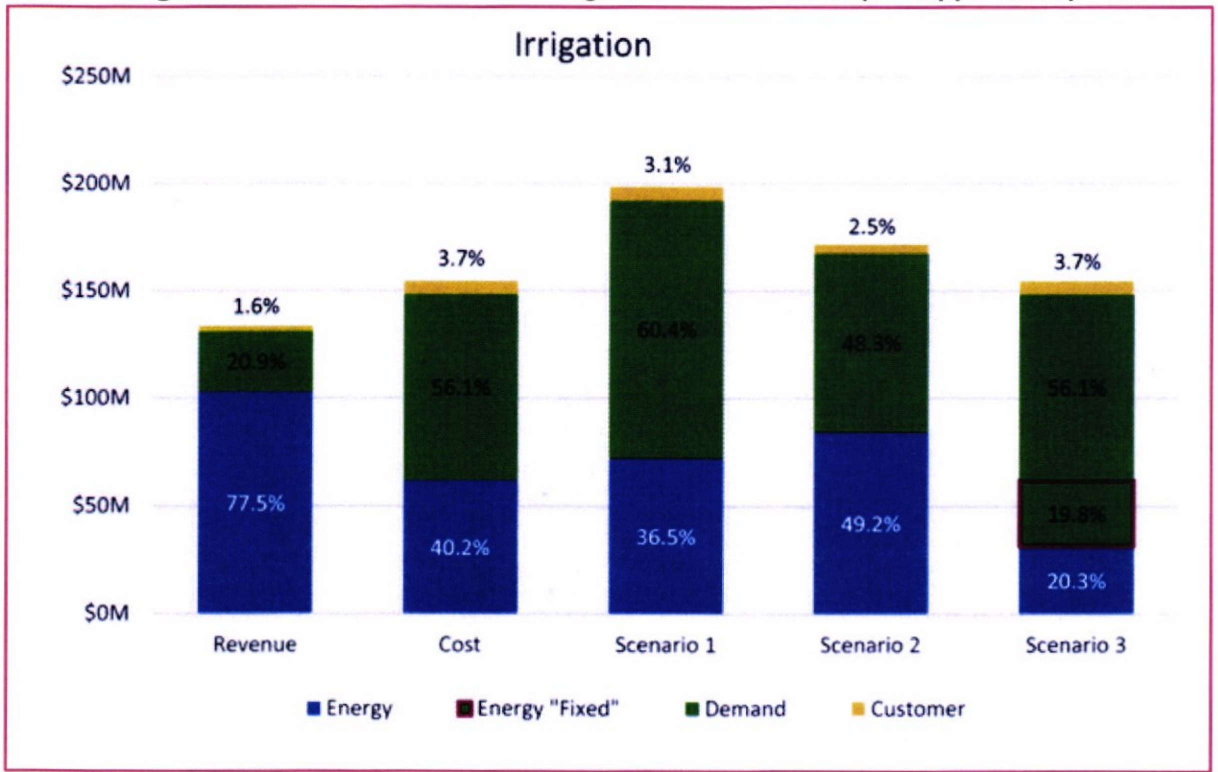

Figure 12 – Cost categories for Irrigation customer class

<u>RESPONSE TO REQUEST NO. 28</u>: Please see the table below for dollar amounts for each of the cost categories for the Irrigation customer class in Appendix G.

	Revenue	Cost	Scenario 1	Scenario 2	Scenario 3
Demand	$27,869,485	$86,589,217	$119,862,911	$82,961,733	$86,589,217
Energy	$103,236,852	$61,946,127	$72,299,431	$84,425,484	$31,350,034
Customer	$2,116,041	$5,749,623	$6,177,781	$4,213,046	$5,749,623
Energy "Fixed"	$0	$0	$0	$0	$30,596,093

Recall that the 18-16 docket sprang from questions related to on-site generation in IPC-E-17-13. When Idaho Power analyzed the suggestion regarding allocating demand charges to a 3-4 hour period they assumed *"Irrigation load shutting down each weekday during these 3-4 hours"*[19] What if, instead of the Irrigation customers "shutting down their load" during the peak hours, those customers self-supplied their load during those same hours?

What if that $33 million increase in Demand costs was recovered under a volumetric TOU rate structure? As detailed in the footnote below, the $33 million could be collected by adding about $.10/kWh[20] to existing volumetric charges. If a $.10/kWh demand charge were added to the existing energy rate for energy Irrigators consume between 2 and 8 pm on summer weekdays, the ability to offset those energy plus demand charges via self-generation could make economic sense for the Irrigation customer.

Having a large and geographically distributed group of irrigators harnessing solar energy in or near the fallow corners around their center pivots would provide a wide assortment of benefits. A substantial amount of solar generation on Irrigators' land would obviously increase the portion of energy produced in Idaho. That generation would also help to backfill as Idaho Power moves off out of state coal-fired generation. Self-generating could improve economic security for the irrigators by limiting their exposure to the future rate increases that an eventual carbon tax might produce. And a final resolution of the inefficiencies that have sprung from the well-intentioned Irrigation class subsidies established back in the "Farm Aid" era of the 1980s is ultimately in all customers' interest.

In spite of requests, TOU rates based on demand charges calculated under Scenario 1 cost allocations and charged to Irrigation customers based on the volumes of energy they used during the peak hours were not evaluated in the Report. We believe that such an analysis must be included in any comprehensive review.

6.2 TOU rates for the Residential class

Growing peak summer loads are driving Idaho Power fixed cost growth. Figure 9 (see section 5.3) shows that most of Idaho Power's high system load hours occur in the summer months. Figure 13 below displays monthly peak loads of Residential customers. That chart shows a pattern of 40 MWs of annual increases in summer peak loads caused by the Residential customer class. Figure 14 provides additional information related to Residential peak load, this time on a diurnal rather than monthly cycle. Collectively, Figures 13 and 14 show how Residential class load is the

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[19] Report p 46

[20] Increased Demand charge of $33,273,640 ($119.862,911 less $86,589,217 per Figure 12) divided by the product of a conservative estimate of Irrigation load at 800,000 kilowatts times an estimate of average annual number of peak load hours occurring on summer non-holiday weekdays of 392 hours (see derivation in section 4.1) implies a rate increase of $.106/kWh during those 392 hours to equal the $33 million amount

critical component of summer peak load growth.

Figure 13 – Residential class peak summer loads are growing fast

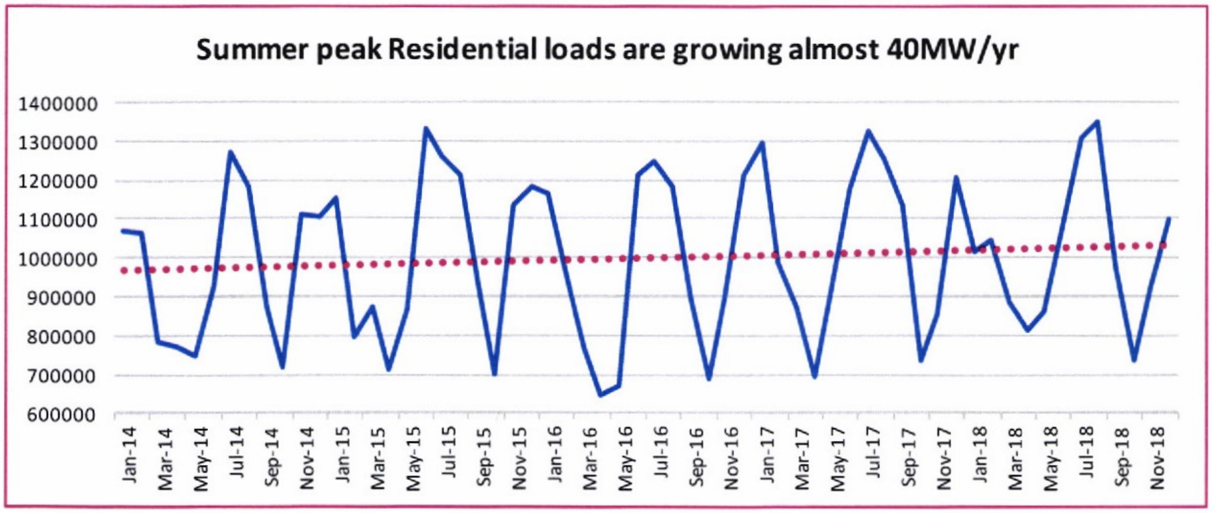
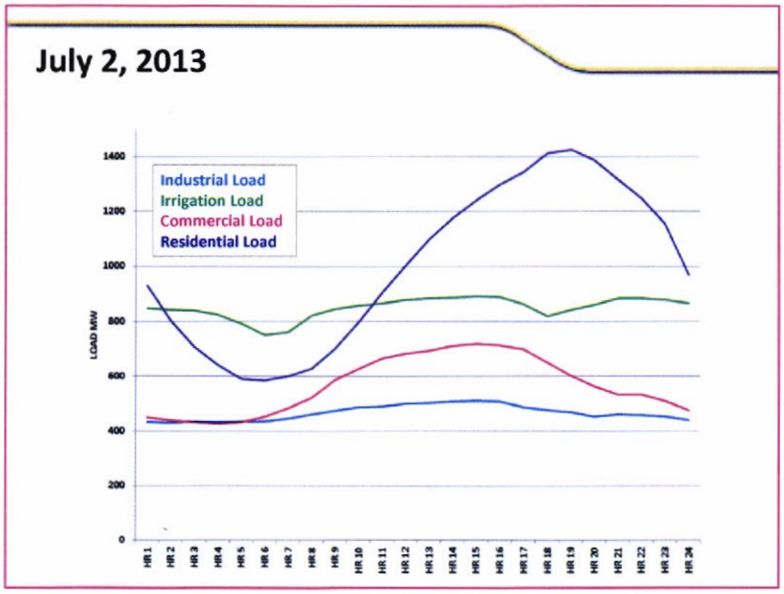


Figure 14 – Class load patterns on system peak days



The data in Figure 14 (taken from a 2015 IRPAC handout) shows the distribution of load across customer classes during what was then the date of the all-time system peak load. The graph shows that while Commercial customer load also rises in the late afternoon, the vast majority of the rise in load being served during the late afternoon system peak load hours is coming from Residential air conditioners.

TOU rates that incent Residential customers to invest in more efficient air conditioners when their unit gets to the end of its useful life would seem like a rate design that should be included in any comprehensive study. And in the Report Idaho Power did analyzed two Residential TOU designs.

The first, the "Cost based" Residential TOU design produced volumetric rates largely based on energy cost differentials. Because that design did not include reflect cost differentials associated with fixed costs it produced differences between on and off peak prices that were so low that they "*may not achieve the behavioral shifts that higher differentials would*".[21] Sierra Club agrees that the differential in Idaho Power's "Cost based" TOU rate design between the $.09/kWh rate during summer on-peak hours and the $.087/kWh summer off-peak rate probably wouldn't shift many consumers' behavior.

Idaho Power provides a reference in footnote 22 on page 34 of the Report to a 2016 rate design review that suggests that high peak to off-peak price ratios align with shifts away from peak hour consumption. And the second Residential TOU rate design in the Report, the "5:1" rate, did have a substantial difference between summer on-peak rates at $.275/kWh and all other hours of the year at $.054/kWh. But Idaho Power dismissed the 5:1 rate structure as one that "*does not reflect the cost to serve*"[22].

In Section 5.3 above Sierra Club explains why we believe that any "cost to serve" calculated by Idaho Power using hopelessly outdated cost allocation methods does not accurately reflect contemporary cost structures. Just as with the requests for review of Irrigation TOU rates based on demand charges calculated under Scenario 1 cost allocations, Sierra Club thinks the 5:1 Residential rate design should have been calculated using Scenario 1 cost allocation methods. That was not done. We believe it should have been.

Residential class air conditioning load is driving Idaho Power fixed cost growth. Use of an out-of-date cost allocation method produces a big subsidy in favor of the Irrigation class. Innovative TOU rates, if analyzed fairly using contemporary cost of service data, could address both issues.

7 CONCLUSION & REQUESTED REMEDY

Rising Residential class air conditioning load is the biggest factor driving Idaho Power fixed cost growth. Out of date cost allocation methods provide a big subsidy in favor of the Irrigation class. A modified cost allocation structure using contemporary cost of service data combined with innovative TOU rates for the Residential and Irrigation classes, could address both issues. The Report fails to provide these two key analyses.

We believe the Report as currently structured is deficient in its review of efficient price signals and equitable cost allocation. As written it neither meets the standard of a comprehensive study nor serves the larger public interest. We ask that Commission reject Idaho Power's Motion.

[21] Report p 33
[22] Report p 34