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LOUIS F. RACINE (1917-2005)
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October 24, 2008

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2008 OCT 24 PM 3:40
IDAHO PUBLIC
UTILITIES COMMISSION

Jean Jewell
IPUC Commission Secretary
P.O. Box 83720
Boise, Idaho 83720-0084

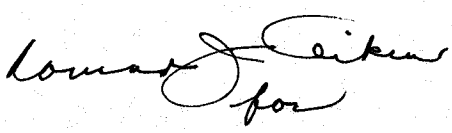
Re: IPC-E-08-10

Dear Mrs. Jewell:

Enclosed for filing you will find the original and nine copies of the Direct Testimony of Anthony Yankel and Sidney Erwin. We are also submitting a searchable CD with the testimony and exhibits contained thereon.

Thank you for your continuing assistance.

Sincerely,



ERIC L. OLSEN

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2008 OCT 24 PM 3:40

IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE.	)))))	CASE NO. IPC-E-08-10

IDAHO IRRIGATION PUMPERS ASSOCIATION, INC.

DIRECT TESTIMONY

OF

ANTHONY J. YANKEL

OCTOBER 24, 2008

1 Q. PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT.

2

3 A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My
4 address is 29814 Lake Road, Bay Village, Ohio, 44140.

5

6 Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL
7 BACKGROUND AND PROFESSIONAL EXPERIENCE?

8

9 A. I received a Bachelor of Science Degree in Electrical Engineering from Carnegie
10 Institute of Technology in 1969 and a Master of Science Degree in Chemical Engineering from
11 the University of Idaho in 1972. From 1969 through 1972, I was employed by the Air
12 Correction Division of Universal Oil Products as a product design engineer. My chief
13 responsibilities were in the areas of design, start-up, and repair of new and existing product lines
14 for coal-fired power plants. From 1973 through 1977, I was employed by the Bureau of Air
15 Quality for the Idaho Department of Health & Welfare, Division of Environment. As Chief
16 Engineer of the Bureau, my responsibilities covered a wide range of investigative functions.
17 From 1978 through June 1979, I was employed as the Director of the Idaho Electrical Consumers
18 Office. In that capacity, I was responsible for all organizational and technical aspects of
19 advocating a variety of positions before various governmental bodies that represented the
20 interests of the consumers in the State of Idaho. From July 1979 through October 1980, I was a
21 partner in the firm of Yankel, Eddy, and Associates. Since that time, I have been in business for
22 myself. I am a registered Professional Engineer in the states of Ohio and Idaho. I have
23 presented testimony before the Federal Energy Regulatory Commission (FERC), as well as the

State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West Virginia.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Idaho Irrigation Pumpers Association, Inc. (Irrigators).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will address:

- Disproportionate growth on the system
- Irrigation Peak Rewards Program
- Allocation of Sales For Resale and Purchase Power based on usage

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS CASE?

A. I make the following conclusions and recommendations:

- There has been very rapid growth on the system for all customer classes except the Irrigators' load which has been flat for at least the last 25 years. The cost of this growth shows up in all aspects of the Company's cost structure; Production, Transmission, and Distribution.

- In spite of the lack of Irrigation growth, the Company's cost-of-service study allocates disproportionate amounts of these costs to the Irrigators. The Irrigators have gotten more than the system average increase for at least the last 15 years.
- If the Company's "Base Case" cost-of-service study were modified to match its marginal cost allocation factors with the growth causing the marginal costs (as opposed to historic usage billing determinants), the rate of return for the Irrigation class would more appropriately reflect the lack of Irrigation contribution to the system growth and growth related costs. If the impact of growth is recognized, the Irrigation rate of return would be over four times the system average. Based upon a proper matching of the Company's marginal costs allocation factors with growth (as opposed to historic billing determinants), I recommend no increase in this case for the Irrigators.
- The Irrigation Peak Rewards Program is about to undergo major improvements that should greatly increase participation levels and become a major resource for Idaho Power to use in controlling its summer peak load. These changes should be in place for next summer's Irrigation season and system peak loads. Any consideration of cost of service and revenue responsibility should reflect the fact that there will be major changes to the system peak loads when these rates are in effect as well as the Irrigation contribution to those peak loads.
- The Company has historically allocated Sales For Resale revenues on a simplistic basis (annual energy usage and/or generation demand

responsibility). Data and computing techniques are available today to match these sales on an hourly basis with the cost causation the makes these sales possible. An example is presented as to how this can be done and a recommendation is made to consider such techniques for future cases.

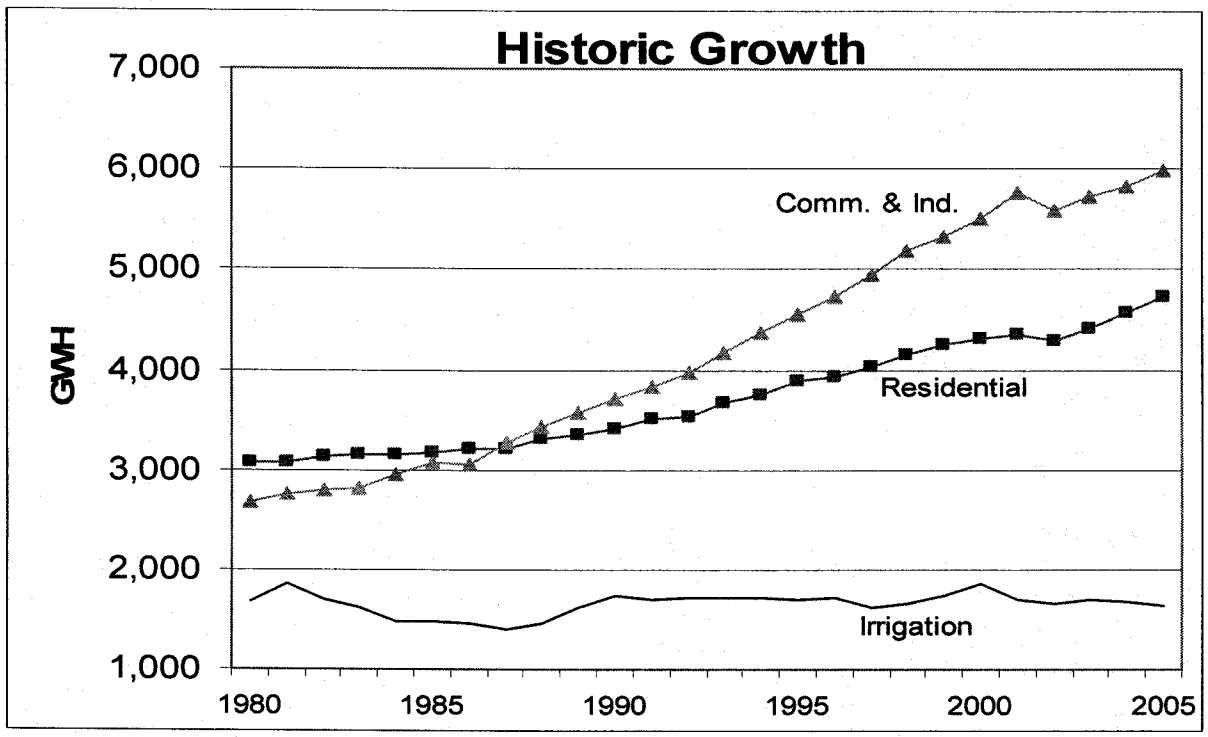
DISPROPORTIONATE GROWTH ON THE SYSTEM

Q. HAS GROWTH ON THE IDAHO POWER SYSTEM BEEN UNIFORM?

A. No. For more than two decades there has been a major imbalance in the growth on the Idaho Power system between customer classes.

Q. UPON WHAT DO YOU BASE YOUR STATEMENT THAT THERE HAS BEEN AN IMBALANCE OF GROWTH ON THE SYSTEM?

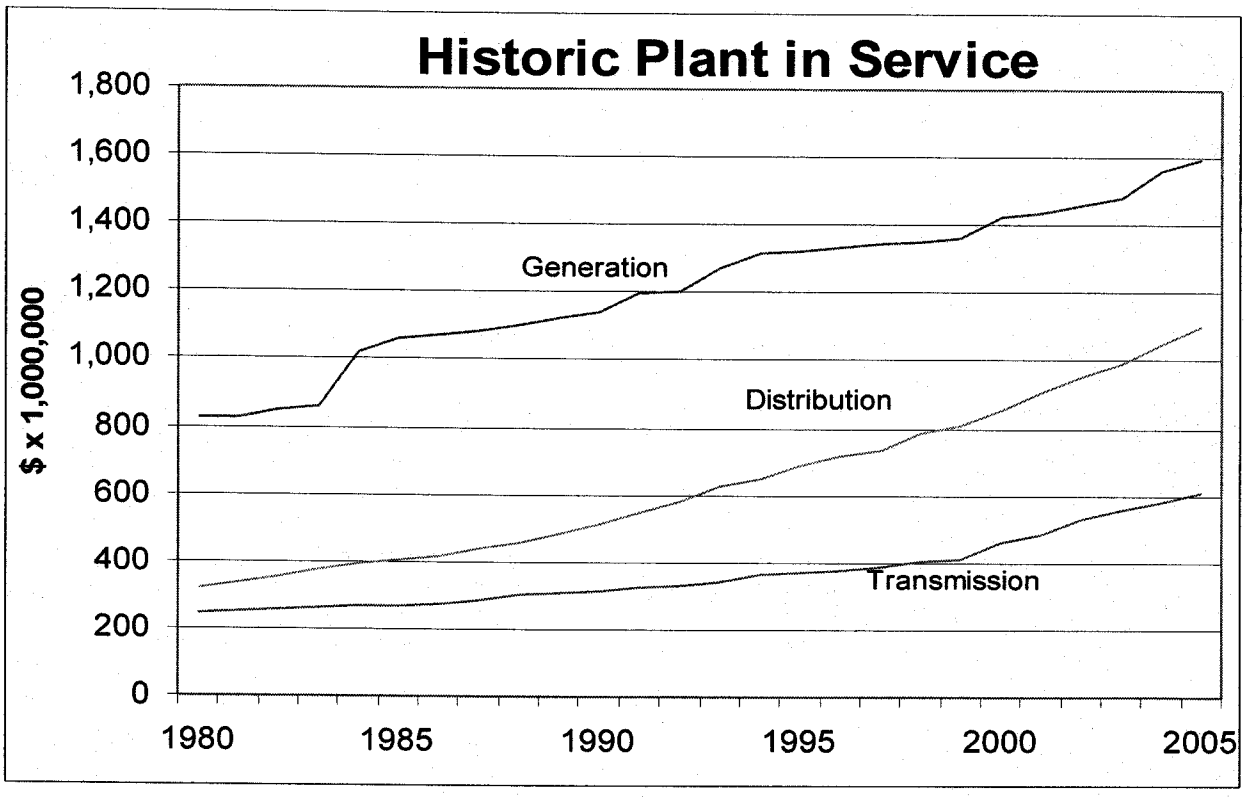
A. Even the most casual observer should note that for years there has been strong and persistent growth on the Idaho Power system and that this growth has not occurred in the Irrigation load. This is most easily demonstrated by observing the following graph[1]:



1 Over the last 25 years, the Irrigation load has been basically flat—decreasing 2%; Residential
2 load has increased 54%; and the combined Commercial/Industrial load has over doubled at an
3 increase of 124%. All customer classes, except the Irrigation class, have caused the phenomenal
4 growth on the Idaho Power system. This pattern is expected to continue.[2]
5
6 Q. WHY DOES THIS GRAPH OF 25 YEARS OF HISTORICAL USAGE END
7 WITH 2005?
8
9 A. The data for this graph came from the Company's 2006 Integrated Resource Plan
10 ("IRP"). I utilized the Company's IRP because it is a source of data where it is possible to get 25
11 years of historical data as well as projected usage, all in one place. The most recent Idaho Power
12 IRP is for 2006. Historical data from the Company's 2006 IRP only goes to 2005. There was a
13 2008 IRP Update, but it did not provide similar historical information.
14
15 Q. HAS THERE BEEN GROWTH IN UTILITY PLANT-IN-SERVICE?
16
17 A. Yes. In order to keep up with this growth, there have been significant increases in
18 Plant-In-Service at all functions as demonstrated by the following graph[3]:

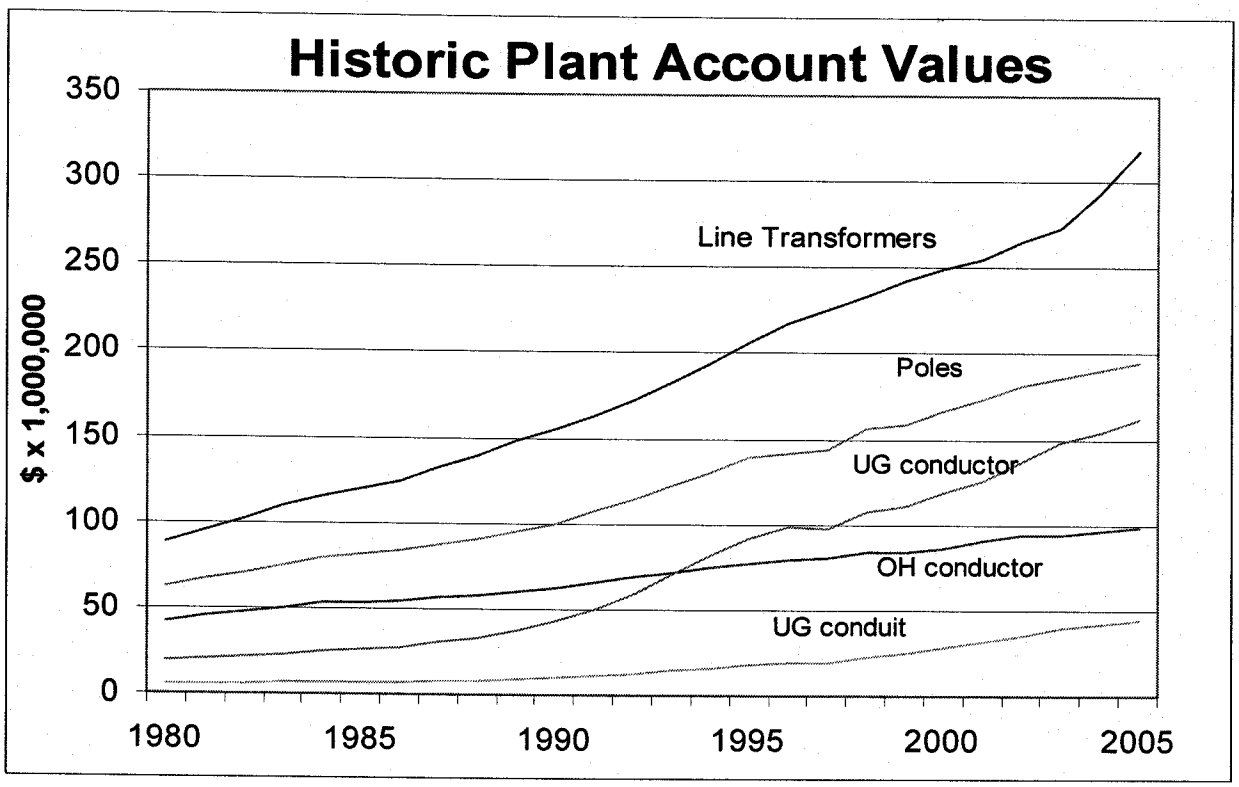
---

[1] Historic usage data taken from pages 25, 27, 29, 31 of Appendix A of Idaho Power's 2006 IRP.
[2] According to Appendix A, page 39 of Idaho Power's 2008 Integrated Resource Plan Update, over the next 10 years Irrigation load is expected to decline slightly, while all of the other classes are expected to experience continued load growth.
[3] Data taken from FERC Form 1 for years 1981-2006.



In the last 25 years, Generation plant has increased $768 million or 93%, Transmission plant has increased $360 million or 145% (more than doubled its 1981 level), and Distribution plant has increased the most by adding an additional $780 million or 246% (over tripled its 1981 level).

Given the huge percentage growth in Distribution Plant-In-Service and the fact that the absolute dollar magnitude even exceeded that of new Generation plant, it is worthwhile to look at these accounts in more detail:



As can be seen from the above graph, the increase in plant-in-service has occurred in all aspects of Distribution Plant. What is not readily apparent from the above graph is the percentage change in various accounts. The Overhead Conductor account has doubled, while the Poles and Line Transformer accounts have tripled in the last 25 years. However, the Underground accounts have gone up over 700% of their levels from 25 years ago.

Q. DOES THE COMPANY'S ALLOCATION METHODS AND COST OF SERVICE STUDIES PROPERLY REFLECT THE IMPACT OF THESE GROWTH RATES ON COSTS TO CUSTOMER CLASSES?

A. No. IPCo witness Gale stated in his testimony in this case[4] that the Company has been advocating cost based rates:

> Idaho Power has consistently advocated for the principle that rate spread among the customer classes and for component pricing within the customer classes should be primarily cost-based. Accordingly, the company's ratemaking proposals have traditionally advocated movement towards cost-of-service results which assign costs to those customers that cause the Company to incur the costs.

Although IPCo tries to follow this policy with respect to the results produced by its cost of service studies, the Company's cost of service study inappropriately allocates a significant portion of this growth to the Irrigation class. Given the obvious fact that growth and the cost of growth are not being fueled by the Irrigators, the allocation of significant portions of the cost of this growth to the Irrigators is on its face counter-intuitive. Additionally, the Company is not properly signaling the rate schedules that are growing that their growth is expensive—thus, promoting additional growth.

Q. PLEASE FURTHER EXPLAIN HOW THE RESULTS OF THE COMPANY'S CLASS COST OF SERVICE STUDY ARE COUNTER-INTUITIVE.

A. As pointed out above, the trend that has been in place for more than two decades is that the non-Irrigation load has increased, while the Irrigation load has either stayed even or decreased. The following lists the annual system peak demand data utilized in both this case and Case IPC-E-94-5 which used a 1993 test year[5] (15 years ago):

---

[4] See the direct testimony of John R. Gale at page 23 lines 16-24.
[5] The non-irrigation data listed for Case IPC-E-94-5 does not include data for FMC.

Annual System Peak	1993	2008	% Change
Irrigation (kW)	572,219	610,726	6.7%
Non-Irrigation (kW)	1,212,428	2,331,457	92.3%

As can be seem from above, the changes in load at the time of the single annual system peak are striking. Over the last 15 years, the rate of growth for the non-irrigation customers has been at a rate that is approximately 14 times greater than that for the Irrigators.

A similar pattern can be seen with respect to the annual energy consumption:

Annual Energy Usage	1993	2008	% Change
Irrigation (MWH)	1,799,035	1,720,416	-4.4%
Non-Irrigation (MWH)	8,867,253	13,316,310	50.2%

As can be seem from above, the changes in annual energy usage follow a diverging pattern. Over the last 15 years the Irrigation usage has decreased usage by almost 5%, while Non-Irrigation usage has increased approximately 50%. As pointed out by Irrigator witness Sidney F. Erwin, the fact that there is a moratorium on new ground water rights in the Snake River Plain Aquifer prohibits Irrigation load from growing due to the lack of water. Although there has been conversion of some flood irrigated land to sprinkler irrigation, much of this limited growth has been offset by more efficient irrigation methods being applied. For the other customer classes, there are far less limitations to their continued growth as predicted by the Company.

Q. WHY IS THIS HISTORIC PRESPECTIVE OF BILLING DETERMINANTS IMPORTANT?

A. It has been an often repeated theme of this rate case as well as past rate cases that growth on the system is causing cost increases and the corresponding need to seek rate increases for the customers. As stated by Company President Mr. Keen in this case[6]:

> Q. Are these actions alone sufficient to ensure a reliable and safe supply of electricity for your customers?
> A. No. The need to expand infrastructure and obtain new energy supplies continues to grow. Our recently filed update of our Commission-accepted Integrated Resource Plan, or "IRP", forecasts the addition of between 12,500 and 13,000 new customers per year over the 20-year planning period. Energy demand is forecast to grow about 30 average megawatts per year with a 70 megawatt-per-year increase in peak demand levels – a growth rate that would be greater if not for our demand-side management efforts during the period. These trends will require continuing expansion of generation and delivery systems and energy efficiency programs. The IRP details our need to add 650 megawatts of supply-side capacity and 225 megawatts of transmission capacity from 2008 through 2012.

Given the substantial growth on the Idaho Power system and the cost of that growth, one would expect that the cost of that growth would be borne by the customers that are causing that growth. Contrary to this premise, the Company's cost of service studies over the last 15 years have proposed to allocate disproportionate increases to the Irrigators in order to pay for the cost of growth of other customers. The following is a listing of the percentage increases recently sought by Idaho Power and the percentages increases that the Company's costs of service studies assigned to the Irrigators as well as Residential and General Service (secondary):

Case No.	Overall Increase	Increase to Irrigators	Increase to Residential	Increase to GS (Sec.)
IPC-E-03-13[7]	17.68%	67.10%	13.38%	8.00%
IPC-E-05-28[8]	7.82%	27.03%	2.76%	7.32%
IPC-E-07-08[9]	10.35%	42.64%	0.11%	9.14%
IPC-E-08-10[10]	9.89%	32.38%	2.01%	9.44%

[6] See direct testimony of J. Lamont Keen at page7 lines 1-17.
[7] Exhibit 41 page 1 line 233
[8] Exhibit 44 page 1 line 53
[9] Exhibit 45 page 1 line 53
[10] Exhibit 57 page 1 line 53

1 Note that in spite of the Irrigators not causing any growth or growth related costs, the
2 Company's cost of service study attempts to give Irrigators percentage rate increases that are
3 significantly above the system average, while those same cost of service studies have always
4 shown the Residential customers and the General Service (secondary) customers as needing less
5 than the average rate increase. Clearly, these Company cost of service studies have been
6 producing counter-intuitive recommendations with respect to the Irrigation customers.
7
8 Q. IS THE ALLOCATION METHODOLOGY IN THE COMPANY'S COST OF
9 SERVICE STUDY IN THIS CASE THE SAME AS THAT FROM 15 YEARS AGO?
10
11 A. Generally speaking, yes. There have been some minor changes compared to 15
12 years ago, but the allocation methodology used by the Company in this case under Exhibits 54-
13 58 (referred to by the Company as its "Base Case") is similar for the major allocators (D10, D13,
14 and E10). If anything, the allocation methodology under the Company's Base Case may be more
15 tolerant of the lack of Irrigation growth than was the allocation methodology used 15 years ago.
16 In spite of the Company's proposed method in this case being "more tolerant of the lack of
17 Irrigation growth", it is still wide-of-the-mark of fairly allocating the cost of growth to those
18 classes that have been growing and thus, causing substantial cost increases to the system.
19
20 Q. HOW DO THE COSTS ALLOCATED TO THE IRRIGATORS AND OTHER
21 CUSTOMERS IN THIS CASE, COMPARED TO THE COST OF SERVICE STUDY
22 PROVIDED 15 YEARS AGO, REFLECT THE LACK OF GROWTH OF THE IRRIGATION
23 CLASS AND THE SIGNIFICANT GROWTH IN OTHER CUSTOMER CLASSES?

A. A comparison of the level of costs allocated to Irrigators in this case with those allocated 15 years ago, demonstrates the counter-intuitive nature of these studies when growth and the cost of growth is not addressed in the allocation factors. A comparison of the allocated Production rate base between this case (IPCo's "Base Case") and the case 15 years ago reveals the following:

Production[11] (x$1000)	1993	2008	% Change
Irrigation	$164,667	$230,329	39.9%
Non-Irrigation	$847,877	$1,533,152	80.8%

Under the Company's allocation method, the Production plant rate base attributed to Irrigators has increased by 40% and the percentage of new Production plant attributed to Irrigators (whose load has been virtually stagnant) is half the percentage increase that has been allocated to all of the customer classes that have been experiencing rapid growth.

The counter-intuitive nature of the Company's allocation methods with respect to this lopsided growth are even better observed with respect to the rate base associated with Transmission plant. A comparison of the allocated Transmission rate base between this case (IPCo's "base case") and the case 15 years ago reveals the following:

Transmission[12] (x$1000)	1993	2008	% Change
Irrigation	$41,271	$ 89,016	115.7%
Non-Irrigation	$207,152	$597,840	188.6%

[11] 1993 data comes from Case No. IPC-E-94-5, Company Exhibit 32, pages 3 and 4. The 2007 data comes from Case No. IPC-E-08-10, Company Exhibit 55 (base case), page 3.
[12] 1993 data comes from Case No. IPC-E-94-5, Company Exhibit 32, pages 3 and 4. The 2007 data comes from Case No. IPC-E-07-08, Company Exhibit 55 (base case), page 3.

In spite of the fact that the overall usage of the Irrigators has been flat and their growth in contribution to the annual system peak has been virtually non-existent in comparison to the other customer groups, the Company's allocation method is giving Irrigators over double the transmission rate base it had 15 years ago and approximately the same percentage increase in new Transmission plant that it is giving all other customer classes.

The counter-intuitive nature of the Company's allocation methods with respect to this lopsided growth can also be observed with respect to the rate base associated with Distribution plant. A comparison of the allocated Distribution rate base between this case (IPCo's "base case") and the case 15 years ago reveals the following:

Distribution[13] (x$1000)	1993	2008	% Change
Irrigation	$105,394	$187,260	77.7%
Non-Irrigation	$425,080	$1,070,312	151.8%

Once again, in spite of the fact that the overall energy usage of the Irrigators has been on the decline and their growth in contribution to the annual system peak has been virtually non-existent in comparison to the other customer groups, the Company's allocation method in this case is giving almost double the dollar amount of Distribution plant-in-service to the Irrigators that was given 15 years ago even though there was no growth by the Irrigators. The Company's allocation method has given approximate half of the percentage increase in new Distribution plant to the Irrigators that it is giving all other customer classes. One would expect only a small amount of this growth in Distribution plant went to serve Irrigation customers.

[13] 1993 data comes from Case No. IPC-E-94-5, Company Exhibit 32, pages 3 and 4. The 2007 data comes from Case No. IPC-E-08-10, Company Exhibit 55 (base case), page 3.

Q. WAS THE WORKSHOP THAT WAS INITIATED AS A RESULT OF THE 2003 CASE ABLE TO COME TO ANY CONCLUSIONS REGARDING THE TREATMENT OF THE ALLOCATION OF THE COSTS ASSOCIATED WITH THIS GROWTH?

A. Although there was general consensus among the workshop participants on a number of issues, the only agreement regarding the treatment of growth in the Company's cost of service study is that there is a disconnect between the classes that were growing and causing the costs to be incurred and the allocation of those costs. Regarding whether new growth was properly covering its cost of service, "The Parties' Final Report in IPC-E-04-23" stated:

> Most of the workshop time was devoted to discussion of this issue. The parties agreed that there was <u>something inherently troubling with the way costs, associated with growth, were allocated. This is evidenced by the relatively large increase in revenue requirement allocated to customers whose load and energy requirements were unchanged or grew only slightly. While there was agreement that the cost of growth did not necessarily get allocated to the customer classes that grew,</u> we were unable to devise a technical remedy to the allocation procedure that would also satisfy the courts. The parties were unable to devise and agree to a cost-of-service allocation methodology that would properly allocate the cost of growth, without making a distinction between new and old customers. Even a search of what others, around the country, were doing produced little in the way of an acceptable solution. Therefore, it was concluded that the only remedy is a policy solution. The parties were not willing to agree to the particulars of such a policy and recommend that the Commission formulate such a policy in the next rate proceeding. (Emphasis added)

Q. WERE THE WORKSHOP PARTICIPANTS ABLE TO DEVELOP A CONSENSUS POSITION THAT DEFINED THE COST IMPACTS OF GROWTH?

A. No. As pointed out above, the workshop participants were not able to develop a consensus method for allocating the cost of growth in a manner that was acceptable to all parties. The problem with attempting to develop a consensus was recognized by various participants at

the workshop. Although there was general consensus that there was something inherently very wrong with the present allocation scheme as related to its ability to allocate the cost of growth, no one felt that they could go back to their clients and admit that they agreed to a methodology that would cost their client more money—this decision was left to the Commission.

Q. DOES THE COMPANY'S APPROACH TO RATEMAKING AND COST ALLOCATION ATTEMPT TO REFLECT COSTS?

A. That is the Company's stated goal, although that may not be the result. The classification and allocation used by the Company, only looks at half of the cost causation equation—it assumes a steady state situation or one with even growth across all classes. The NARUC Electric Utility Cost Allocation Manual makes a general statement that is right on target in this situation:

> The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. (emphasis added)[14]

As a general statement, I believe all parties would agree with this NARUC policy. As demonstrated above, there has been a tremendous amount of growth on the system over the last 25 years with associated costs to support that growth. For all practical purposes, the Irrigators have not participated in that rapid growth and were not the cause of the costs associated with that growth. However, as has been demonstrated above, the Company's cost of service studies do not address the disproportionate cost of growth and, thus, do not accomplish this goal.

1 Q. IS THE COMPANY ADVOCATING THE SAME GENERAL ALLOCATION
2 METHODOLOGY IN THIS CASE AS IT DID OVER THE PAST 15 YEARS?
3
4 A. No. Although the Company provided as its Base Case an allocation methodology
5 that is similar to what it has proposed in the past, it is favoring a new classification/allocation
6 method in this case. The results of the Company's Base Case are contained in Mr. Tatum's
7 Exhibit 57. The new method favored by Mr. Tatum and the Company, classifies/allocates
8 Production costs based upon function (base, intermediate, and peak) during the three summer
9 months. The results of the Company's preferred method are contained in Mr. Tatum's Exhibit
10 66. The Company is not proposing any changes to its Transmission, Energy, or Distribution
11 allocators. Thus, there is very little overall change.
12
13 Q. IS THE NEW ALLOCATION METHOD ADVOCATED BY THE COMPANY
14 FOR PRODUCTION RELATED COSTS AN IMPROVEMENT OVER THE PAST METHOD
15 THAT IT ADVOCATED?
16
17 A. Only very marginally. This new method only addresses Production cost and it
18 still suffers from the same shortcomings as the Company's past studies—it allocates costs on a
19 stagnant basis, with no recognition of the impact of growth on costs. This new method still
20 suggests that the Irrigation customers pay a substantial amount for the cost of growth for which
21 they have not caused.
22

---

[14] Electric Utility Cost Allocation Manual, published by the National Association of Regulatory Utility Commissioners 1992 at page 39.

Q. DOES THE COMPANY BASE CASE ALLOCATION METHODOLOGY RECOGNIZE THE NEED TO RECOGNIZE GROWTH IN ITS ALLOCATION METHODOLOGY?

A. Although the Company's Base Case allocation methodology falls short of recognizing the disparity of growth on the system, it has been stated that it is the Company's intention to do so. In Case IPC-E-05-28 Company witness Brilz[15] offered the following with respect to the Company's thoughts regarding the Base Case methodology:

> Q. What is the reasoning for using marginal cost weightings in the derivation of the demand-and energy- related allocation factors?
>
> A. The use of marginal cost weighting is intended to strike a balance between backward-looking costs already incurred and forward-looking costs to be incurred in the future.

The exact same language appears in Mr. Tatum's testimony in the 2007 rate case[16]. Mr. Tatum provides very similar testimony in this case.[17] The intent is appropriate—the execution falls short of the goal.

The balance between historic and forward looking costs that is struck in the Company's study is 50% based upon an unweighted 12-CP allocation that is designed to reflect today's share of cost causation on the system[18]. The other 50% of the allocation factor purports to reflect forward-looking costs and this is where the major disconnect occurs. The Company inappropriately defines forward-looking costs using the same test-year 12-CP usage characteristics (present day usage) and combines it with marginal weighting factors that reflect

[15] Case No. IPC-E-05-28, witness Brilz at page 19.
[16] Tatum testimony in Case No. IPC-E-07-08, page 25, line 10.
[17] Tatum testimony in Case No. IPC-E-07-08, page 36, lines 2-4.
[18] For purposes of this discussion, I accept this part of the Company's method. However, this approach ignores the lopsided growth that has taken place for over two decades on the system.

1 "forward-looking costs to be incurred in the future" in order to meet growth. Thus, the Irrigators
2 (as well as all classes) get assigned costs, based upon weighting factors designed to reflect
3 growth that is going to be incurred by the System in the future, but not based upon the
4 usage/growth that is going to create those costs. Thus, unrealistic results occur where the
5 Irrigation load is stagnant or decreasing, but the cost of the system growth is being assigned to it,
6 not based upon future growth of the Irrigators, but based upon the present usage of the Irrigators.
7
8 Q. HOW COULD THE COMPANY'S BASE CASE ALLOCATION
9 METHODOLOGY BE BETTER ALIGNED TO REFLECT "BACKWARD-LOOKING COSTS
10 ALREADY INCURRED AND FORWARD-LOOKING COSTS TO BE INCURRED IN THE
11 FUTURE"?
12
13 A. The simplest way to correct the Company's Base Case study would be to continue
14 to define "backward-looking costs" based on test year usage levels and "forward-looking costs"
15 at the anticipated increase in usage levels in the Company's IRP. The "backward-looking costs"
16 would simply be costs as they exist today and allocated on the basis of today's energy or 12-CP
17 as is presently done in the Company's "base" cost of service study. The "forward-looking costs"
18 would be developed using the same weighting factors used by the Company associated with the
19 cost of the anticipated growth, but would be allocated on the basis of only the growth that is
20 anticipated from each rate schedule over a future ten year period. The relative share of historic
21 costs and anticipated costs related to growth would then be averaged using the Company's
22 existing procedure in order to develop a composite allocation factor for use in spreading test year
23 costs for allocation purposes. In this manner, the methodology would be exactly the same as the

1 Company's Base Case, but the marginal costs would be tied to the marginal/new usage and not
2 to the present level (status quo) of usage.
3
4 Q. HOW COULD THE CHANGE THAT YOU PROPOSE BE IMPLEMENTED
5 TO THE COMPANY'S COST OF SERVICE STUDY IN ORDER TO INSURE THAT THIS
6 COUNTER-INTUITIVE RESULT DOES NOT CONTINUE IN THE FUTURE?
7
8 A. One very simple change could be made. Instead of combining the Company's
9 growth related weighting factors with existing billing determinants, they could be combined with
10 forecasted growth—making an apples-to-apples comparison.
11 The Company's 2006 IRP[19] that served as a basis for developing the weighted cost
12 factors can also serve as the source of the data for the forecasted growth as well. In Exhibit 301,
13 I have simply modified the Company's allocation weighting procedure to apply the marginal cost
14 weightings developed by the Company to only the growth that is expected over the next ten
15 years[20]. For example, the Company's Exhibit 59 page 1 takes the May normalized demand for
16 the Residential class of 894,322 and multiplies it by a weighting of 10.41 in order to develop a
17 weighted demand of 9,309,897. The starting figure of 894,322 is a test year value and not
18 reflective of the growth that will take place on the system. Only the future growth in Residential
19 load should be used for this calculation.

[19] This is the last IRP where a full range of forecasts and data was provided. The 2008 Update did not contain detailed data to break out growth by grouping.
[20] A ten year growth horizon was chosen to give some stability to the numbers without forecasting out so far that reliability concerns would be raised. Although a five year growth horizon would have produced more beneficial allocators for the Irrigators, it was felt that a ten year growth horizon would be preferable.

According to the Company's 2006 IRP[21], the average load for the Residential class will increase from 4,865,000 to 5,811,000 billed MWh or 19.45% between 2006 and 2016. Thus, instead of using the Company's billing unit of 894,322, a value for expected growth must be used. The expected growth for Residential load in May can be estimated at 173,946 MWh (894,322 MWH x 0.1945) over the next ten years. This value of 173,946 MWh should be multiplied by the Company's weighting factor of 10.41. Similar adjustments to only include the growth portion of each class' load in the Company's method needs to be made.

Q. DID YOU PROPOSE THIS MECHANISM AS A MEANS OF REFLECTING THE COST OF GROWTH TO THE WORSHOP IN CASE IPC-E-04-23?

A. No. The proposal I made to the Workshop was one that looked backward and tried to capture the amount of growth and the cost of growth that took place over the previous 25 years. The Workshop was not able to come to an agreement regarding that proposed methodology as a means of properly allocating the cost of growth. The methodology that I am proposing here is forward looking and it matches the future marginal costs the Company employs in its cost of service study with future growth. It does not attempt to separate "old electrons" from "new electrons" or "new customers" from "old customers."

Q. WHAT GROWTH PERCENTAGES DID YOU INCORPORATE INTO YOUR REVISION OF THE COMPANY'S BASE CASE COST OF SERVICE STUDY?

[21] Idaho Powers 2006 IRP—Sales and Load Forecast page 26.

1 A. Using the Company's 2006 IRP[22], the following growth percentages were
2 calculated:

Residential	19.45%
Commercial (Sch. 7, 9, 40, 42)	30.04%
Industrial (Sch. 19)	27.24%
Irrigation	1.03%
Special Contracts	9.38%

8 I utilized these percentages as the basis for calculating the amount of growth (beyond test year
9 billing determinants) associated with the Generation and Transmission plant (allocators D10,
10 D13, and E10). I made no calculation to reflect the growth in Distribution plant that is larger
11 than the growth in either Generation or Transmission plant.
12
13 Q. WHAT IS THE IMPACT ON THE COMPANY'S BASE CASE COST OF
14 SERVICE STUDY WHEN ITS GROWTH RELATED WEIGHTING FACTORS ARE
15 APPLIED TO FORECAST GROWTH AS OPPOSED TO HISTORIC/PRESENT USAGE AND
16 HOW DO THOSE RESULTS COMPARE WITH THE BASE CASE STUDY IN THE
17 COMPANY FILING?
18
19 A In spite of the fact that this change is only directed at 50% of the allocation factor,
20 as can be seen from Exhibit 302, there is a major difference between the indexed rates of return
21 that result from using weighting factors that are properly aligned with expected growth,

[22] Idaho Powers 2006 IRP—Sales and Load Forecast pages 26-36

compared to the Company's Base Case study that does not link marginal cost weighting factors with growth. The indexed rates of return for the major rate schedules are summarized below:

Study	Res.	Sch. 9 (s)	Sch. 19	Irr.
Growth Corrected[23]	1.309	-0.173	-0.211	4.574
Company's Base Case[24]	1.231	1.011	0.789	0.505

Although the difference between these two cost of service runs is quite large for some rate schedules, it should come as little surprise. It has been well recognized by virtually all parties that the Company's present allocation method does not properly address the cost of growth and the fact that for at least twenty-five years the Irrigators have been getting saddled with costs that they have not placed upon the system. In fact, the Irrigators have often gotten rate increases larger than the system average.

By way of contrast, the Growth Corrected study follows more intuitive logic. The growth on the system over the last two-plus decades has not been even across all classes. Irrigation load has been virtually flat, Residential load has increased rapidly, but not as rapidly as Commercial and Industrial load. Given the growth in average system load[25] of 20.7% that is predicted over the next ten years in the 2006 IRP, any rate group that would be growing less than the average should be getting a smaller share (compared to its size) of the marginal costs, while those growing faster should get a higher percentage. The Irrigation growth is essentially zero and Special Contract growth is less than the average, so this Growth Correction increases the rate of return for those classes over that produced by the Company's Base Case study. Residential growth is about the system average, so there is little impact of using the Growth Corrected

[23] Irrigation Exhibit 301, line 38.
[24] Company Exhibit 55, page 1, line 52.
[25] Idaho Powers 2006 IRP Sales and Forecast at page 36 shows sales in 2016 of 16,817 GWh compared to 13,938 GWh in 2006 for a difference of 20.7%.

method compared to the Company's Base Case. The Commercial and Industrial load growth is above average system growth so the Commercial and Industrial customer's rate of return is lowered. Given the fact that the Corrected Growth cost of service run recognizes the link between growth and the growth related weighting factors, the resulting indexed rates of return are quite logical:

- The Residential growth rate is somewhat less than the system average; therefore, the indexed rate of return goes up a little when compared to the Company's Base Case.
- The Commercial growth rate is significantly above system average; therefore, the indexed rate of return for Schedule 9 significantly drops when compared to the Company's Base Case.
- The Industrial growth rate is above system average (but not as much as Commercial); therefore, there is a substantial drop in the indexed rate of return for Schedule 19 when compared to the Company's Base Case.
- The Irrigation growth rate is essentially non-existent; therefore, the indexed rate of return goes up a great deal when few of the growth related costs are allocated to it compared to the Company's Base Case.

Q. DO THE RESULTS OF THE COST OF SERVICE STUDY IN EXHIBIT 302 REFLECT THE GROWTH DIFFERENTIAL THAT IS ASSOCIATED WITH THE DISTRIBUTION SYSTEM?

A. No. Exhibit 302 only reflects changes to the Company's cost of service study to reflect growth on the Generation and Transmission system. Over the last 25 years, the growth in

1 Plant-in-Service associated with the Distribution system has been greater than both the
2 Generation and Transmission system. A methodology needs to be adopted for addressing the
3 growth on the Distribution system as well. It should be remembered that not only have the
4 Irrigators had very little impact for the past 25-plus years on the cost of the Company's
5 distribution plant, the Irrigators have virtually nothing to do with the costs associated with the
6 Company's Underground Distribution costs.
7
8 Q. THE GROWTH FACTORS THAT YOU INPORPORATED INTO THE
9 COMPANY'S STUDY ARE BASED UPON ENERGY GROWTH AND NOT DEMAND. IS
10 THIS A PROBLEM?
11
12 A. No. First, there is only energy data available in the Company's 2006 IRP
13 regarding forecast usage. Admittedly, the use of forecast demand levels by rate schedules would
14 have a higher appeal, although not necessarily be more accurate. If demand forecasts by class
15 become available, I have no problem substituting that data.
16 Second, the impact of using demand as opposed to energy values may give the
17 appearance of being more accurate, but in the overall scheme of things, growth in energy and
18 growth in demand are highly (although not 100%) correlated with each other. The fact that all
19 classes are undergoing significant growth, while the Irrigator load is virtually stagnant, is the
20 major factor involved. Once this watershed difference is recognized, the rest is simply icing on
21 the cake.
22 Third, I am not making a proposal to right all of the wrongs that have occurred over the
23 last 25 years because the Irrigators have been penalized for costs that they did not cause. I am

simply trying to get recognition of the problem and begin to make minor corrections as we continue to move through a period of rapid growth on the system by most, but not all, classes of customers.

Q. HOW SHOULD THE RESULTS OF EXHIBIT 302 BE UTILIZED FOR PURPOSES OF THIS CASE?

A. The issue of addressing growth in the Company's cost of service study is a new direction for the Commission, and one that generally has not been faced by other commissions across the country. As the Final Report in the IPC-E-04-23 Workshop stated: "The parties agreed that there was something inherently troubling with the way costs, associated with growth, were allocated." As recognized at the Workshop, the cost causation of growth is indisputable and the lack of growth on the part of the Irrigators is indisputable as well. Recognizing that the Commission moves cautiously (but deliberately) in these matters, I recommend that Exhibit 302 be used to generally direct the Commission's ordered rate spread in this case.

Q. BASED UPON THE GENERAL RESULTS OF EXHIBIT 302, WHAT PORTION OF THE RATE INCREASE IN THIS CASE DO YOU RECOMMEND FOR THE IRRIGATORS?

A. Over the last several rate cases, the Irrigators have been given the same or a higher percentage increase than the system average. These increases have been given because the Company's cost-of-service studies have never addressed the disproportionate growth and

associated costs between the classes. There was no growth on the part of the Irrigators to cause the costs to be incurred that were associated with the rate increases being sought. The following represents a brief picture of the increases that have been given to the Irrigators because this disproportionate growth and cost causation has not been recognized:

Case #	Order #	Ave. Increase	Irrigation Increase
07-08	30508	5.20%	5.65%
05-28	30035	3.20%	3.20%
03-13	29505	5.20%	13.95%
94-05	25880	4.19%	10.23%

Over the last 10-plus years, the Irrigators have gotten well over the average rate increase, in spite of the fact that they have not been causing the growth and the need for the rate increases on the system. Based upon the greater than average increases which have been given to the Irrigators in the past and the results of the simple correction/alignment of marginal costs with the growth causing those costs which demonstrates[26] that the Irrigators should be given a significant decrease in rates; I recommend that the Irrigators be given no increase in this case. I recommend that the Residential class be given the average rate increase, and that Schedules 9 and 19 be given larger than average increases.

Q. WHY SHOULD THERE BE ANY GROWTH ADJUSTMENT IN A COST OF SERVICE STUDY WHEN EVEN WITH RATE SCHEDULES THERE WILL BE SOME CUSTOMERS CAUSING THE GROWTH WHILE OTHERS ARE NOT?

A. Just because one may not wish to set rates on the basis of individual customers that are causing the growth, this is no excuse for ignoring the larger picture that significant

1 growth is taking place, and that growth is well defined on a class or rate schedule level. Rates
2 have always been set for a group of similarly situated customers and not on the particular
3 characteristics of individual customers, unless that customer was very large and unique. It is also
4 my understanding that there are possible discrimination problems when seeking to charge
5 individual customers within a class different rates based upon when they first took service. With
6 respect to this prohibition, I am not proposing a difference of rates among individual customers
7 within a class based on growth, but the assignment of growth related costs to the classes that are
8 causing those growth related costs. From that perspective, my adjustment is essentially the same
9 as that proposed by the Company when it used marginal cost weighting factors in order to
10 allocate production and transmission plant.

11 Additionally, growth is not a simple question of defining who are the new customers.
12 Growth in load is taking place both because of new customers as well as because of increased
13 usage by existing customers.

14 At this time, the Irrigators are looking for some recognition by the Commission (as was
15 given by the Workshop from Case IPC-E-04-23) that there is "<u>something inherently troubling</u>
16 <u>with the way costs, associated with growth, were allocated.</u>" Some initial attempt to recognize
17 this problem in the allocation of revenue requirement in this case would greatly move this
18 discussion forward, without causing a major disruption in class revenue requirement in this case.

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[26] Exhibit 302 line 43

IRRIGATION PEAK REWARDS PROGRAM

Q. IS THERE SOMETHING NEW HAPPENING WITH RESPECT TO THE COMPANY'S IRRIGATION PEAK REWARDS PROGRAM?

A. Yes. The Company, Irrigators and the Staff have been meeting to discuss possible improvements in this program for the benefit of all. A new program, modeled off of the "company option" load management program in the PacifiCorp service area, will soon be brought before the Commission with the hope of having the program in place before the 2009 Irrigation Season. The Irrigators are very supportive of this program as well as the one offered in the PacifiCorp service area that interrupts electricity to irrigation pumps at the Company's option during the summer super-peak hours as opposed to just on designated days of the week as the current program does. The Irrigation Peak Rewards Program is a workable program that produces tangible benefits for the Company as well as all ratepayers.

Q. HOW MUCH BENEFIT CAN BE EXPECTED OUT OF THIS NEW PEAK REWARDS PROGRAM?

A. Both the Irrigators and the Company are hopeful that this new "company option" program will be very successful for the Irrigators and the system as a whole. The PacifiCorp service area in Idaho has an Irrigation load during the annual system peak of approximately 255 MW. Under this new program PacifiCorp has signed up approximately 215 MW of Irrigation load that it can interrupt at any time (presumably at peak times for the Company). PacifiCorp is still working with this program in order to get the maximum benefit from it. Unlike the previous

1 program that PacifiCorp had or the Peak Rewards program that Idaho Power presently has,
2 interruptions are only occurring when the Company needs the electricity and not merely
3 occurring because a clock states that the designated day and designated time have arrived for an
4 interruption—irrespective of need. With PacifiCorp having control over approximately 85%
5 (215 MW / 255 MW) of its Irrigation load, great strides can be made in the reduction of costs
6 and the reduction of peaking resources.
7 According to Idaho Power's filing in this case, the IPCo Irrigators' contribution to the
8 annual coincident peak is approximately 650 MW. I do not expect to see 85% of the IPCo
9 Irrigation load on this new Peak Rewards program, but if there was even 50% participation, this
10 would yield a peak reduction capability of 325 MW. By comparison, Idaho Power's present
11 Peak Rewards program has only been yielding approximately 40 MW of reduction on a system
12 where the Irrigation load is over 2.5 times larger than that on the PacifiCorp system.
13
14 Q. WHAT BENEFIT DOES THE IRRIGATION PEAK REWARDS PROGRAM
15 PROVIDE TO THE SYSTEM?
16
17 A. On July 11, 2007 Quantec issued a Report to PacifiCorp (Rocky Mountain
18 Power) entitled "Assessment of Long-Term, System-Wide Potential for Demand-Side
19 and Other Supplemental Resources". This Report was designed to (and virtually did)
20 cover all aspects of DSM or alternative resources. The Irrigation Load Curtailment
21 program was viewed as one of only three "firm" DSM options that represent a Class 1
22 resource. Of these three Class 1 options, the Irrigation Load Curtailment program had the
23 lowest costs per unit of avoided capacity and in fact these costs were calculated to be less

than half of the cost of the next closest option (direct load control of air conditioners). The Irrigation Load Curtailment program was calculated to have an avoided cost of capacity in the Rocky Mountain Power region of $98/kW-year.

Q. HOW APPLICABLE TO IDAHO POWER IS THAT REPORT'S AVOIDED CAPACITY FIGURE OF $98/KW-YEAR FOR ROCKY MOUNTAIN POWER?

A. Although these are different utilities, they operate in the same general market, and in this case, both operate in southern Idaho. According to the Company's 2006 IRP, the following resources are being pursued with the associated costs:

	$/kW-month[27]	$/kW-year
170 MW Simple Cycle CT (non-fuel)	$5.53	$69
100 MW Wind	$16.40	$197
50 MW Geothermal	$33.68	$404
Expansion of DSM		
Residential Existing Const.	$5.34	$64
Commercial Existing Const.	$10.15	$122
Industrial Efficiency	$10.26	$123

Based upon these options that IPCo is pursuing, the $98/kW-year figure is a good representation of the avoided cost of a program like the Irrigation Peak Rewards program.

Q. WHAT WILL BE THE COST OF THE NEW IRRIGATION PEAK REWARDS PROGRAM?

[27] Levelized cost of generation taken from IPCo's 2006 IRP, Appendix D, page 59. Levelized DSM costs taken from IPCo's 2006 IRP, pages 67 and 68.

1 A. Because of the newness of the program, similar data and calculations are not
2 available. The credit to be paid to participants in the new program will be approximately $32 per
3 kW. Of course there will be the cost of the equipment, installation costs and some level of
4 ongoing O&M. Collectively, these costs should be substantially below the $98 per kW benefit
5 that was calculated for a similar program for PacifiCorp. There will be a large dollar benefit not
6 only for the Irrigators that participate, but for all customers on the system.
7
8 Q. HAS THE COMPANY'S PEAK REWARDS PROGRAM BENEFITED THE
9 IRRIGATORS, BY WAY OF THE COMPANY'S COST OF SERVICE STUDY IN THIS
10 CASE?
11
12 A. Yes. The interruptibility of the Irrigators is reflected in this case. If there was an
13 interruption at the time of any of the monthly peaks, there was an attempt to reflect the level of
14 that interruption in the Company's cost of service study.
15
16 Q. IS THE COMPANY'S METHOD OF FLOWING THROUGH THE LEVEL OF
17 INTERRUPTIONS INTO THE COST OF SERVICE STUDY IN THIS CASE
18 APPROPRIATE?
19
20 A. The treatment of the level of interruptions in this case, may have been appropriate
21 for now, but these methods will probably need to be adjusted for the future. Basically, the
22 problem faced by the Company is that for most classes it has load research meters that it uses to
23 gather data regarding what the peak contribution to system peak is for customers within a given

1 sample. The problem with the Irrigators is that the sample must not only represent the general
2 population, but it needs to represent the level of interruptions as well. Under the existing Peak
3 Rewards program there were a host of interruption options and days during which an Irrigator
4 could be involved—all adding complexity. The Company's solution to this problem thus far has
5 been to pull out of the load research data any customers that may have been interrupted and then
6 determine the level of interruptions from other data.
7 If there is a large level of participation as expected with the new program, the present
8 scheme may not work. Basically, such a large participation could wreak havoc on the load
9 research sample that was set up for other purposes. Additionally, the new program is not
10 designed for Irrigation pumps less than 30 hp, which would mean that all of the interruptible
11 customers would be in load research strata 2, 3, and 4, but not stratum 1. It is quite possible that
12 for such a large level of participation that the load research sample may need to be redesigned in
13 order to reflect two groups of customers—interruptible and firm.
14
15 Q. WHY IS IT IMPORTANT TO LOOK AT COST OF SERVICE RESULTS
16 FROM A PROGRAM THAT WILL NOT BE IMPLEMENTED UNTIL NEXT YEAR?
17
18 A. Rates set in this case will be implemented in the future. Given the seasonality of
19 the Irrigation load, these rates will be implemented for them at the same time as the new Peak
20 Rewards program will be implemented. Normally, test year loads and costs are used as the basis
21 for setting future rates. However, "normally" implies that the past (test year) will be a reflection
22 of the future when rates are in effect. As was addressed above, "normally" does not properly
23 address the fact that the Irrigation load is not causing growth and the costs associated with that

growth. Likewise, "normally" does not address the watershed change in Irrigation load that will take place under the new Peak Rewards program.

Q. WHAT WOULD BE THE IMPACT OF A 50% REDUCTION IN SYSTEM PEAK CONTRIBUTION IN THIS CASE IF THE NEW PEAK REWARDS PROGRAM HAD BEEN IN EFFECT FOR THE TEST YEAR?

A. The exact impact would be difficult to calculate because there are a lot of assumptions that would need to be made with respect to what impact the operation of this new Peak Rewards program would have upon the overall system load. It would have impacted the time and date of the monthly peaks—and the resulting class contributions to those peaks as they vary by day and hour of the day. For purposes of estimating the impact of the new Peak Rewards program during the test year, I have simply assumed that the Irrigation peak contribution is cut in half for the months of June and July (the only two months when the new peak rewards program will be operating).

Exhibit 303 contains a summary page of the cost of service results under the Company's base case and assuming that the Irrigation peak contribution to the June and July system peaks were cut in half. As can be seen from Exhibit 303, the Irrigation rate of return has been increased from 3.36% in the Company's base case up to 5.12%, just below the system average of 6.61%. Exhibit 304 contains a similar summary page that is the cost of service result based upon the same assumptions regarding the impact of the Irrigation Peak Rewards program, but using the Company's new/preferred 3CP/12CP

1 cost of service study. As can be seen from Exhibit 304, the Irrigation rate of return has
2 been increased up to 6.19%, just below the system average of 6.61%.
3
4 Q. HOW DO THE EXPECTED RESULTS OF THE COMPANY'S COST OF
5 SERVICE STUDIES REFLECT HOW COSTS SHOULD BE ALLOCATED TO THE
6 IRRIGATORS IN THIS CASE?
7
8 A. The Irrigation load is seasonal and thus, rates in this case for the Irrigators will be
9 implemented next year—the same time that the new Peak Rewards program will be
10 implemented. Rates for the Irrigators (like other classes) should be implemented in a manner
11 that reflects expectations at the time of implementation. The Irrigation load will be substantially
12 different in 2009 and rates should attempt to reflect that difference. Implementation of the new
13 Peak Rewards program will essentially put the Irrigators at the system average cost of service
14 (absent any recognition for the negative impact that the 25 years of disproportionate growth has
15 had on the Irrigators). Based simply on the adoption of the new Peak Rewards program (that
16 does not have to be anywhere near as successful as the results obtained for PacifiCorp), the
17 Irrigators should get no more than the system average rate increase.

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,258,924	1,212,734	35,886	62,277	504,772	1,585	286,259	1,175
February		2,173,492	1,131,967	32,372	61,108	509,120	604	286,641	1,314
March		2,086,837	1,090,878	28,203	57,969	476,970	0	281,695	7,216
April		1,811,290	802,562	27,783	56,398	442,372	0	275,603	66,714
May		2,379,445	894,322	27,544	62,981	505,591	0	295,698	454,868
June		2,717,244	915,130	41,392	67,686	585,274	0	319,495	649,453
July		2,942,183	1,147,411	39,396	71,720	596,516	0	332,193	610,726
August		2,769,652	1,100,716	36,822	68,242	562,721	0	305,224	553,816
September		2,632,345	1,012,375	35,299	67,253	581,385	0	306,209	491,934
October		1,832,555	778,189	24,151	63,165	453,491	750	304,809	62,185
November		2,056,441	977,038	32,199	64,168	513,995	992	307,324	10,222
December		2,371,004	1,237,243	37,436	62,013	569,430	1,437	308,749	1,651
Total		28,031,411	12,300,566	398,482	764,980	6,301,638	5,369	3,609,900	2,911,274
Ratio		1.0000	0.4388	0.0142	0.0273	0.2248	0.0002	0.1288	0.1039
Actual	D10S	0.3183	0.1128	0.0042	0.0074	0.0622	0.0000	0.0341	0.0823
Actual	D10NS	0.6817	0.3260	0.0100	0.0199	0.1626	0.0002	0.0946	0.0216
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									
2006 Billed MWh x 1000			4,865	3,802	3,802	3,802	3,802	2,438	1,650
2016 Billed MWh x 1000			5,383	4,389	4,389	4,389	4,389	2,768	1,654
			10.65%	15.44%	15.44%	15.44%	15.44%	13.54%	0.24%
Monthly Coincident Demands Weighted by Marginal Demand Costs									
Power Supply Service - Generation									
January	0.00	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	10.41	2,414,132	991,270	44,270	101,224	812,599	0	416,657	11,479
June	10.55	2,669,025	1,027,974	67,422	110,249	953,318	0	456,244	16,610
July	11.30	3,181,156	1,380,525	68,732	125,125	1,040,703	0	508,100	16,730
August	5.58	1,487,358	653,968	31,722	58,791	484,790	0	230,533	7,492
September	6.77	1,757,027	729,755	36,896	70,296	607,685	0	280,600	8,074
October	0.00	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0
December	5.39	1,517,759	710,053	31,153	51,605	473,866	1,196	225,255	22
Total		13,026,457	5,493,545	280,194	517,291	4,372,961	1,196	2,117,390	60,407
Ratio		1.0000	0.4217	0.0215	0.0397	0.3357	0.0001	0.1625	0.0046
Weighted	D10S	0.5639	0.2351	0.0129	0.0226	0.1903	0.0000	0.0917	0.0038
Weighted	D10NS	0.4361	0.1866	0.0086	0.0171	0.1454	0.0001	0.0708	0.0009
Average	D10S	0.43199	0.17397	0.00854	0.01499	0.12626	0.00000	0.06293	0.04301
Average	D10NS	0.56801	0.25630	0.00932	0.01851	0.15399	0.00014	0.08273	0.01124
Total Ratio		1.00000	0.43027	0.01786	0.03350	0.28025	0.00014	0.14566	0.05425

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,103	5,801	589	2,113,180	37,597	23,776	84,371	145,744
February		2,119	2,210	580	2,028,035	37,558	23,523	84,376	145,457
March		2,139	0	572	1,945,643	33,631	23,607	83,956	141,194
April		2,146	0	564	1,674,140	27,925	24,164	85,060	137,149
May		2,168	0	555	2,243,728	23,008	23,508	89,201	135,717
June		2,171	0	547	2,581,149	25,614	19,737	90,744	136,095
July		2,174	0	539	2,800,676	24,157	23,561	93,789	141,507
August		2,137	0	530	2,630,208	23,136	24,485	91,823	139,444
September		2,183	0	522	2,497,161	21,736	22,851	90,597	135,184
October		2,185	2,809	514	1,692,248	31,101	24,231	84,974	140,307
November		2,192	3,762	505	1,912,398	35,001	23,383	85,659	144,043
December		2,192	5,456	497	2,226,105	35,643	23,529	85,726	144,899
Total		25,911	20,038	6,513	26,344,670	356,108	280,355	1,050,277	1,686,741
Ratio		0.0009	0.0007	0.0002	0.9398	0.0127	0.0100	0.0375	0.0602
Actual	D10S	0.0002	0.0000	0.0001	0.2858	0.0026	0.0024	0.0099	0.0149
Actual	D10NS	0.0007	0.0007	0.0002	0.6540	0.0101	0.0076	0.0276	0.0453
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									
2006 Billed MWh x		3,802	3,802	3,802		1,183	1,183	1,183	
2016 Billed MWh x		4,389	4,389	4,389		1,210	1,210	1,210	
		15.44%	15.44%	15.44%		2.28%	2.28%	2.28%	
Monthly Coincident Demands Weighted by Marginal Demand Costs									
Power Supply Service - Generation									
January	0.00	0	0	0	0	0	0	0	0
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	10.41	3,485	0	893	2,381,887	5,467	5,585	21,193	32,245
June	10.55	3,537	0	891	2,636,255	6,168	4,752	21,850	32,770
July	11.30	3,794	0	940	3,144,661	6,230	6,077	24,189	36,495
August	5.58	1,841	0	457	1,469,599	2,946	3,118	11,694	17,759
September	6.77	2,282	0	545	1,736,139	3,359	3,531	13,998	20,888
October	0.00	0	0	0	0	0	0	0	0
November	0.00	0	0	0	0	0	0	0	0
December	5.39	1,824	4,541	413	1,499,934	4,385	2,894	10,546	17,825
Total		16,763	4,541	4,139	12,868,475	28,554	25,958	103,470	157,982
Ratio		0.0013	0.0003	0.0003	0.9879	0.0022	0.0020	0.0079	0.0121
Weighted	D10S	0.0007	0.0000	0.0002	0.5566	0.0012	0.0011	0.0044	0.0067
Weighted	D10NS	0.0006	0.0003	0.0001	0.4313	0.0010	0.0009	0.0035	0.0054
Average	D10S	0.00047	0.00000	0.00012	0.42121	0.00189	0.00174	0.00715	0.01078
Average	D10NS	0.00064	0.00053	0.00016	0.54264	0.00556	0.00425	0.01556	0.02537
Total Ratio		0.00111	0.00053	0.00028	0.96385	0.00745	0.00600	0.02271	0.03615

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,258,924	1,212,734	35,886	62,277	504,772	1,585	286,259	1,175
February		2,173,492	1,131,967	32,372	61,108	509,120	604	286,641	1,314
March		2,086,837	1,090,878	28,203	57,969	476,970	0	281,695	7,216
April		1,811,290	802,562	27,783	56,398	442,372	0	275,603	66,714
May		2,379,445	894,322	27,544	62,981	505,591	0	295,698	454,868
June		2,717,244	915,130	41,392	67,686	585,274	0	319,495	649,453
July		2,942,183	1,147,411	39,396	71,720	596,516	0	332,193	610,726
August		2,769,652	1,100,716	36,822	68,242	562,721	0	305,224	553,816
September		2,632,345	1,012,375	35,299	67,253	581,385	0	306,209	491,934
October		1,832,555	778,189	24,151	63,165	453,491	750	304,809	62,185
November		2,056,441	977,038	32,199	64,168	513,995	992	307,324	10,222
December		2,371,004	1,237,243	37,436	62,013	569,430	1,437	308,749	1,651
Total		28,031,411	12,300,566	398,482	764,980	6,301,638	5,369	3,609,900	2,911,274
Actual	D13	1.0000	0.4388	0.0142	0.0273	0.2248	0.0002	0.1288	0.1039
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									
2006 Billed MWh x 1000			4,865	3,802	3,802	3,802	3,802	2,438	1,650
2016 Billed MWh x 1000			5,811	4,944	4,944	4,944	4,944	3,102	1,667
			19.45%	30.04%	30.04%	30.04%	30.04%	27.24%	1.03%
Monthly Coincident Demands Weighted by Marginal Transmission Costs									
Transmission Service									
January	6.29	3,217,950	1,483,284	67,799	117,661	953,674	2,995	490,393	76
February	5.40	2,670,298	1,188,600	52,506	99,116	825,786	980	421,567	73
March	6.11	2,884,716	1,296,062	51,760	106,388	875,359	0	468,765	454
April	3.10	1,251,316	483,781	25,870	52,514	411,911	0	232,691	2,131
May	21.79	9,843,195	3,789,306	180,277	412,212	3,309,107	0	1,754,847	102,119
June	21.66	10,695,773	3,854,335	269,298	440,361	3,807,781	0	1,884,765	144,934
July	24.47	13,373,459	5,459,606	289,563	527,143	4,384,401	0	2,213,906	153,973
August	16.85	8,717,129	3,606,480	186,362	345,388	2,848,047	0	1,400,727	96,146
September	18.31	9,232,874	3,604,441	194,134	369,876	3,197,470	0	1,527,007	92,803
October	6.43	2,652,134	972,981	46,645	121,995	875,858	1,449	533,793	4,120
November	6.94	3,281,784	1,318,498	67,120	133,762	1,071,452	2,069	580,886	731
December	10.68	5,789,342	2,569,418	120,091	198,932	1,826,695	4,609	898,073	182
Total		73,609,821	29,626,792	1,551,424	2,925,348	24,387,539	12,102	12,407,420	597,742
Weighted	D13	1.00000	0.40248	0.02108	0.03974	0.33131	0.00016	0.16856	0.00812
Average	D13	1.00000	0.42065	0.01765	0.03352	0.27806	0.00018	0.14867	0.05599

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January	0.00	2,103	5,801	589	2,113,180	37,597	23,776	84,371	145,744
February	0.00	2,119	2,210	580	2,028,035	37,558	23,523	84,376	145,457
March	0.00	2,139	0	572	1,945,643	33,631	23,607	83,956	141,194
April	0.00	2,146	0	564	1,674,140	27,925	24,164	85,060	137,149
May	0.00	2,168	0	555	2,243,728	23,008	23,508	89,201	135,717
June	0.00	2,171	0	547	2,581,149	25,614	19,737	90,744	136,095
July	0.00	2,174	0	539	2,800,676	24,157	23,561	93,789	141,507
August	0.00	2,137	0	530	2,630,208	23,136	24,485	91,823	139,444
September	0.00	2,183	0	522	2,497,161	21,736	22,851	90,597	135,184
October	0.00	2,185	2,809	514	1,692,248	31,101	24,231	84,974	140,307
November	0.00	2,192	3,762	505	1,912,398	35,001	23,383	85,659	144,043
December	0.00	2,192	5,456	497	2,226,105	35,643	23,529	85,726	144,899
Total		25,911	20,038	6,513	26,344,670	356,108	280,355	1,050,277	1,686,741
Actual	D13	0.0009	0.0007	0.0002	0.9398	0.0127	0.0100	0.0375	0.0602
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									
2006 Billed MWh x		3,802	3,802	3,802		1,183	1,183	1,183	
2016 Billed MWh x		4,944	4,944	4,944		1,294	1,294	1,294	
		30.04%	30.04%	30.04%		9.38%	9.38%	9.38%	
Monthly Coincident Demands Weighted by Marginal Transmission Costs									
Transmission Service									
January	6.29	3,974	10,960	1,112	3,131,934	22,189	14,032	49,795	86,016
February	5.40	3,438	3,585	941	2,596,598	19,030	11,919	42,752	73,700
March	6.11	3,925	0	1,050	2,803,770	19,280	13,534	48,132	80,946
April	3.10	1,998	0	525	1,211,423	8,123	7,029	24,742	39,893
May	21.79	14,192	0	3,635	9,565,715	47,041	48,063	182,375	277,480
June	21.66	14,127	0	3,558	10,419,181	52,057	40,112	184,423	276,592
July	24.47	15,982	0	3,959	13,048,558	55,464	54,097	215,340	324,900
August	16.85	10,814	0	2,684	8,496,664	36,579	38,712	145,174	220,464
September	18.31	12,008	0	2,869	9,000,627	37,343	39,259	155,647	232,248
October	6.43	4,220	5,425	992	2,567,484	18,764	14,619	51,267	84,650
November	6.94	4,570	7,841	1,053	3,187,987	22,792	15,226	55,779	93,797
December	10.68	7,033	17,503	1,594	5,644,140	35,718	23,578	85,906	145,202
Total		96,281	45,314	23,972	71,674,081	374,380	320,179	1,241,330	1,935,888
Weighted	D13	0.00131	0.00062	0.00033	0.97370	0.00509	0.00435	0.01686	0.02630
Average	D13	0.00112	0.00067	0.00028	0.95676	0.00889	0.00718	0.02717	0.04324

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
ENERGY RELATED ALLOCATION FACTORS									
Monthly Energy Requirements @ Generation Level									
January		1,274,427	612,425	22,375	37,265	301,939	544	193,019	858
February		1,122,676	518,667	18,253	33,789	273,341	547	178,930	897
March		1,117,677	482,641	17,128	35,234	288,100	552	185,330	5,269
April		1,015,976	388,521	14,385	33,345	259,325	551	173,777	47,141
May		1,187,259	362,501	15,169	36,268	284,693	551	183,370	202,869
June		1,368,775	364,366	16,174	36,557	285,496	551	193,305	380,683
July		1,654,970	513,947	19,237	39,957	337,989	551	196,830	443,660
August		1,516,012	460,745	18,250	40,421	327,322	553	195,878	371,723
September		1,218,353	374,947	15,226	36,764	291,459	553	189,758	213,480
October		1,076,046	389,435	15,300	38,344	285,143	553	200,848	45,406
November		1,121,665	483,023	16,754	36,421	281,844	549	195,573	7,223
December		1,362,890	674,712	23,395	35,918	326,172	550	194,534	1,206
Total		15,036,726	5,625,931	211,645	440,283	3,542,822	6,606	2,281,153	1,720,416
Ratio		1.0000	0.3741	0.0141	0.0293	0.2356	0.0004	0.1517	0.1144
Actual	E10S	0.3019	0.0891	0.0036	0.0078	0.0632	0.0001	0.0390	0.0937
Actual	E10NS	0.6981	0.2851	0.0105	0.0215	0.1724	0.0003	0.1127	0.0207
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									
	2006 Billed MWh x 1000		4,865	3,802	3,802	3,802	3,802	2,438	1,650
	2016 Billed MWh x 1000		5,811	4,944	4,944	4,944	4,944	3,102	1,667
			19.45%	30.04%	30.04%	30.04%	30.04%	27.24%	1.03%
Monthly Energy Requirements Weighted by Marginal Energy Costs									
Power Supply Service - Generation									
January	73.48	21,396,695	8,750,448	493,840	822,468	6,664,120	12,017	3,862,815	649
February	68.83	17,725,590	6,941,847	377,360	698,566	5,651,141	11,309	3,354,253	636
March	66.76	17,179,303	6,265,400	343,451	706,533	5,777,142	11,065	3,369,743	3,624
April	55.69	12,578,023	4,207,263	240,622	557,771	4,337,856	9,211	2,635,747	27,049
May	55.10	12,894,821	3,883,909	251,047	600,250	4,711,757	9,124	2,751,788	115,168
June	52.41	12,505,053	3,713,302	254,622	575,492	4,494,362	8,677	2,759,247	205,562
July	99.66	28,707,255	9,959,737	575,864	1,196,112	10,117,597	16,508	5,342,524	455,551
August	81.85	22,360,051	7,333,102	448,685	993,766	8,047,268	13,584	4,366,558	313,475
September	72.13	17,308,771	5,258,889	329,881	796,512	6,314,620	11,986	3,727,786	158,650
October	72.07	17,522,232	5,457,558	331,200	830,045	6,172,644	11,981	3,942,366	33,716
November	79.15	20,444,077	7,434,082	398,300	865,876	6,700,598	13,053	4,215,944	5,891
December	80.35	24,985,502	10,541,747	564,621	866,869	7,872,016	13,281	4,257,117	998
Total		225,607,373	79,747,283	4,609,495	9,510,260	76,861,121	141,796	44,585,888	1,320,968
Ratio		1.0000	0.3535	0.0204	0.0422	0.3407	0.0006	0.1976	0.0059
Weighted	**E10S**	**0.28249**	**0.09311**	**0.00567**	**0.01226**	**0.10044**	**0.00017**	**0.05527**	**0.00502**
Weighted	**E10NS**	**0.71751**	**0.26037**	**0.01476**	**0.02990**	**0.24025**	**0.00046**	**0.14236**	**0.00083**

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
ENERGY RELATED ALLOCATION FACTORS									
Monthly Energy Requirements @ Generation Level									
January		1,507	1,992	422	1,172,346	23,043	17,521	61,517	102,081
February		1,518	2,001	416	1,028,360	20,824	15,845	57,647	94,317
March		1,532	2,010	410	1,018,205	20,284	17,536	61,654	99,473
April		1,537	2,019	404	921,004	18,043	17,038	59,892	94,973
May		1,553	2,027	398	1,089,401	17,802	17,533	62,523	97,858
June		1,556	2,036	392	1,281,116	16,179	10,283	61,197	87,659
July		1,558	2,045	386	1,556,162	16,470	17,513	64,824	98,808
August		1,531	2,054	380	1,418,858	15,618	17,534	64,001	97,154
September		1,564	2,063	374	1,126,189	14,937	16,644	60,583	92,164
October		1,565	2,072	368	979,035	17,607	17,217	62,188	97,011
November		1,571	2,081	362	1,025,401	19,386	16,826	60,052	96,264
December		1,571	2,090	356	1,260,503	22,332	17,559	62,496	102,387
Total		18,564	24,491	4,666	13,876,578	222,525	199,048	738,575	1,160,148
Ratio		0.0012	0.0016	0.0003	0.9228	0.0148	0.0132	0.0491	0.0772
Actual	E10S	0.0003	0.0004	0.0001	0.2830	0.0032	0.0030	0.0126	0.0189
Actual	E10NS	0.0009	0.0012	0.0002	0.6398	0.0116	0.0102	0.0365	0.0583
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									
2006 Billed MWh x		3,802	3,802	3,802		1,183	1,183	1,183	
2016 Billed MWh x		4,944	4,944	4,944		1,294	1,294	1,294	
		30.04%	30.04%	30.04%		9.38%	9.38%	9.38%	
Monthly Energy Requirements Weighted by Marginal Energy Costs									
Power Supply Service - Generation									
January	73.48	33,258	43,967	9,306	20,692,889	158,875	120,797	424,134	703,806
February	68.83	31,393	41,372	8,592	17,116,468	134,488	102,333	372,301	609,122
March	66.76	30,726	40,297	8,219	16,556,201	127,057	109,844	386,201	623,102
April	55.69	25,717	33,767	6,755	12,081,757	94,280	89,027	312,959	496,266
May	55.10	25,710	33,554	6,586	12,388,893	92,038	90,647	323,242	505,928
June	52.41	24,490	32,059	6,168	12,073,982	79,561	50,569	300,941	431,072
July	99.66	46,633	61,224	11,553	27,783,303	154,013	163,765	606,173	923,952
August	81.85	37,634	50,505	9,339	21,613,919	119,948	134,658	491,526	746,132
September	72.13	33,891	44,704	8,098	16,685,016	101,091	112,642	410,022	623,755
October	72.07	33,885	44,857	7,964	16,866,214	119,061	116,426	420,532	656,018
November	79.15	37,343	49,479	8,602	19,729,167	143,970	124,962	445,978	714,910
December	80.35	37,909	50,440	8,590	24,213,588	168,365	132,379	471,171	771,915
Total		398,589	526,224	99,772	217,801,396	1,492,747	1,348,049	4,965,181	7,805,977
Ratio		0.0018	0.0023	0.0004	0.9654	0.0066	0.0060	0.0220	0.0346
Weighted	**E10S**	**0.00048**	**0.00064**	**0.00012**	**0.27317**	**0.00157**	**0.00155**	**0.00620**	**0.00931**
Weighted	**E10NS**	**0.00128**	**0.00170**	**0.00032**	**0.69223**	**0.00505**	**0.00443**	**0.01581**	**0.02529**

IIPA Growth Weighted

BASE CASE CLASS COST OF SERVICE STUDY

TWELVE MONTHS ENDING DECEMBER 31, 2008

****** REVENUE REQUIREMENT SUMMARY ******

	SOURCES & N	(A) TOTAL	(B) RESIDENTIAL (1)	(C) GEN SRV (7)	(D) GEN SRV PRIMARY (9-P)	(E) GEN SRV SECONDARY (9-S)	(F) AREA LIGHTING (15)	(G) LG POWER PRIMARY (19-P)	(H) IRRIGATION SECONDARY (24-S)	(I) UNMETERED GEN SERVICE (40)	(J) MUNICIPAL ST LIGHT (41)	(K) TRAFFIC CONTROL (42)	(L) SC DOE/INL	(M) SC JR SIMPLOT	(N) SC MICRON
TOTAL RATE BASE		2,093,398,859	941,020,299	49,509,922	63,321,266	542,236,705	1,047,698	266,974,202	164,908,434	3,218,448	3,775,900	647,846	10,475,756	11,962,432	34,299,952
REVENUES FROM RATES															
RETAIL		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL OTHER OPERATING REVENUES		136,722,443	50,184,302	2,744,404	6,573,000	41,656,044	167,946	27,502,488	2,219,152	215,185	448,291	54,373	853,632	1,283,321	2,820,304
TOTAL REVENUES		809,891,983	368,140,763	17,905,783	22,108,089	183,565,220	1,172,454	97,773,594	79,264,726	1,181,676	2,762,552	209,576	6,681,807	6,301,480	22,824,262
OPERATING EXPENSES															
WITHOUT INC TAX		662,531,282	282,019,741	16,839,131	22,411,994	187,973,914	908,755	100,816,437	28,208,455	1,111,183	2,291,730	244,365	3,568,442	3,422,576	12,714,559
OPERATING INCOME															
BEFORE INCOME TAXES		147,360,700	86,121,022	1,066,652	(303,905)	(4,408,693)	263,700	(3,042,844)	51,056,271	70,492	470,823	(34,789)	3,113,365	2,878,904	10,109,703
TOTAL FEDERAL INCOME TAX		19,062,439	8,568,908	450,836	576,602	4,937,594	9,540	2,431,061	1,501,652	29,307	34,383	5,899	95,392	108,930	312,335
TOTAL STATE INCOME TAX		(3,661,479)	(1,645,901)	(86,596)	(110,753)	(948,404)	(1,832)	(466,954)	(288,435)	(5,629)	(6,604)	(1,133)	(18,323)	(20,923)	(59,993)
TOTAL OPERATING EXPENSES		677,932,243	288,942,748	17,203,372	22,877,844	191,963,104	916,463	102,780,544	29,421,673	1,134,861	2,319,509	249,131	3,645,511	3,510,582	12,966,901
TOTAL OPERATING INCOME		131,959,740	79,198,015	702,411	(769,755)	(8,397,883)	255,992	(5,006,950)	49,843,053	46,815	443,044	(39,555)	3,036,295	2,790,898	9,857,361
ADD: IERCO OPERATING INCOME	E1(	6,472,703	2,287,959	132,247	272,850	2,205,155	4,068	1,279,174	37,899	11,436	15,097	2,862	42,827	38,676	142,451
CONSOLIDATED OPER INCOME		138,432,443	81,485,974	834,658	(496,904)	(6,192,728)	260,060	(3,727,776)	49,880,952	58,251	458,141	(36,693)	3,079,123	2,829,574	9,999,812
RATES OF RETURN		6.613	8.659	1.686	-0.785	-1.142	24.822	-1.396	30.248	1.810	12.133	-5.664	29.393	23.654	29.154
RATES OF RETURN - INDEX		1.000	1.309	0.255	-0.119	-0.173	3.754	-0.211	4.574	0.274	1.835	-0.856	4.445	3.577	4.409
AVERAGE MILLS/KWH		53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66	57.74	104.79	36.89	27.11	26.47	28.44
REVENUE REQUIREMENT CALCULATION															
RATE OF RETURN REQUIRED		8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE		739,757,827	316,267,272	20,741,618	25,240,742	228,202,788	724,577	113,872,889	18,292,711	1,322,685	2,092,096	306,404	2,242,957	2,051,417	8,399,671
REVENUE DEFICIENCY		66,588,287	(1,689,189)	5,580,239	9,705,653	86,293,612	(279,931)	43,601,783	(58,752,863)	356,194	(222,165)	151,201	(3,585,218)	(2,966,742)	(11,604,287)
PERCENT CHANGE REQUIRED		9.89%	-0.53%	36.81%	62.48%	60.81%	-27.87%	62.05%	-76.26%	36.85%	-9.60%	97.42%	-61.52%	-59.12%	-58.01%
RETURN AT CLAIMED ROR		178,985,602	80,457,236	4,233,098	5,413,968	46,361,238	89,578	22,826,294	14,099,671	275,177	322,839	55,391	895,677	1,022,788	2,932,646
EARNINGS DEFICIENCY		40,553,159	(1,028,739)	3,398,440	5,910,873	52,553,966	(170,482)	26,554,070	(35,781,281)	216,927	(135,301)	92,084	(2,183,446)	(1,806,786)	(7,067,166)
REVENUE REQUIREMENT FOR RATE DESIGN															
TOTAL IDAHO SALES REVENUES		673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
REQUESTED CHANGE IN REVENUE (%)		9.89%	-0.53%	36.81%	62.48%	60.81%	-27.87%	62.05%	-76.26%	36.85%	-9.60%	97.42%	-61.52%	-59.12%	-58.01%

Exhibit 302

IIPA 50% Peak value June and July

IPCo's BASE CASE CLASS COST OF SERVICE STUDY

****** REVENUE REQUIREMENT SUMMARY ******

TWELVE MONTHS ENDING DECEMBER 31, 2008

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
TOTAL RATE BASE	2,093,398,859	958,876,971	43,494,829	51,392,518	444,064,327	925,027	226,902,457	266,742,989	2,752,099	3,277,083	509,263	17,641,008	18,383,839	58,436,449
REVENUES FROM RATES														
RETAIL	673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL SALES REVENUES	673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL OTHER OPERATING REVENUES	136,722,443	52,785,619	2,017,642	5,072,246	29,494,922	143,978	22,103,206	14,875,778	151,275	366,154	37,917	1,757,553	2,098,544	5,817,610
TOTAL REVENUES	809,891,983	370,742,080	17,179,021	20,607,335	171,404,098	1,148,486	92,374,312	91,921,352	1,117,766	2,680,415	193,120	7,585,728	7,116,703	25,821,568
OPERATING EXPENSES														
WITHOUT INC TAX	662,531,282	290,940,601	14,039,760	16,688,191	141,396,897	821,096	80,583,980	77,065,317	872,294	2,003,043	181,131	7,045,096	6,563,322	24,330,551
OPERATING INCOME														
BEFORE INCOME TAXES	147,360,700	79,801,479	3,139,260	3,919,144	30,007,200	327,390	11,790,331	14,856,035	245,471	677,371	11,989	540,631	553,381	1,491,017
TOTAL FEDERAL INCOME TAX	19,062,439	8,731,511	396,063	467,979	4,043,639	8,423	2,066,168	2,428,955	25,061	29,841	4,637	160,639	167,403	532,121
TOTAL STATE INCOME TAX	(3,661,479)	(1,677,133)	(76,075)	(89,889)	(776,695)	(1,618)	(396,866)	(466,549)	(4,814)	(5,732)	(891)	(30,855)	(32,154)	(102,209)
TOTAL OPERATING EXPENSES	677,932,243	297,994,979	14,359,748	17,066,282	144,663,842	827,902	82,253,283	79,027,723	892,541	2,027,152	184,877	7,174,880	6,698,570	24,760,463
TOTAL OPERATING INCOME	131,959,740	72,747,102	2,819,273	3,541,053	26,740,256	320,585	10,121,029	12,893,629	225,224	653,262	8,242	410,848	418,133	1,061,105
ADD: IERCO OPERATING INCOME	6,472,703	2,430,500	91,265	187,708	1,516,554	2,589	970,258	759,895	7,767	10,356	1,942	94,501	85,440	313,926
CONSOLIDATED OPER INCOME	138,432,443	75,177,602	2,910,538	3,728,762	28,256,810	323,174	11,091,287	13,653,524	232,992	663,619	10,184	505,349	503,573	1,375,031
RATES OF RETURN	6.613	7.840	6.692	7.255	6.363	34.937	4.888	5.119	8.466	20.250	2.000	2.865	2.739	2.353
RATES OF RETURN - INDEX	1.000	1.186	1.012	1.097	0.962	5.283	0.739	0.774	1.280	3.062	0.302	0.433	0.414	0.356
AVERAGE MILLS/KWH	53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66	57.74	104.79	36.89	27.11	26.47	28.44
REVENUE REQUIREMENT CALCULATION														
RATE OF RETURN REQUIRED	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE	739,757,827	329,132,536	16,488,559	16,627,509	157,854,128	603,722	83,914,276	92,074,802	970,289	1,684,672	209,977	7,475,030	6,772,219	25,950,109
REVENUE DEFICIENCY	66,588,287	11,176,075	1,327,180	1,092,420	15,944,952	(400,786)	13,643,170	15,029,228	3,798	(629,589)	54,774	1,646,855	1,754,060	5,946,151
PERCENT CHANGE REQUIRED	9.89%	3.51%	8.75%	7.03%	11.24%	-39.90%	19.42%	19.51%	0.39%	-27.20%	35.29%	28.26%	34.95%	29.72%
RETURN AT CLAIMED ROR	178,985,602	81,983,981	3,718,808	4,394,060	37,967,500	79,090	19,400,160	22,806,526	235,304	280,191	43,542	1,508,306	1,571,818	4,996,316
EARNINGS DEFICIENCY	40,553,159	6,806,379	808,270	665,299	9,710,690	(244,084)	8,308,873	9,153,001	2,313	(383,428)	33,358	1,002,957	1,068,246	3,621,286
REVENUE REQUIREMENT FOR RATE DESIGN														
TOTAL IDAHO SALES REVENUES	673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
REQUESTED CHANGE IN REVENUE (%)	9.89%	3.51%	8.75%	7.03%	11.24%	-39.90%	19.42%	19.51%	0.39%	-27.20%	35.29%	28.26%	34.95%	29.72%

Exhibit 303

IIPA 50% Peak value June and July

IPCo's3CP/12CP CLASS COST OF SERVICE STUDY

****** REVENUE REQUIREMENT SUMMARY ******

TWELVE MONTHS ENDING DECEMBER 31, 2008

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
				GEN SRV	GEN SRV	AREA	LG POWER	IRRIGATION	UNMETERED	MUNICIPAL	TRAFFIC	SC	SC	SC
	TOTAL	RESIDENTIAL	GEN SRV	PRIMARY	SECONDARY	LIGHTING	PRIMARY	SECONDARY	GEN SERVICE	ST LIGHT	CONTROL	DOE/INL	JR SIMPLOT	MICRON
		(1)	(7)	(9-P)	(9-S)	(15)	(19-P)	(24-S)	(40)	(41)	(42)			
TOTAL RATE BASE	2,093,398,859	960,439,217	43,580,331	51,528,001	444,554,129	916,327	227,584,748	263,380,769	2,763,199	3,344,758	534,230	17,766,917	18,367,949	58,638,283
REVENUES FROM RATES														
RETAIL	673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL SALES REVENUES	673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
TOTAL OTHER OPERATING REVENUES	136,722,443	52,743,896	2,017,391	5,083,503	29,570,218	143,252	22,196,423	14,695,207	151,563	368,897	38,420	1,767,877	2,097,723	5,848,075
TOTAL REVENUES	809,891,983	370,700,357	17,178,770	20,618,592	171,479,394	1,147,760	92,467,529	91,740,781	1,118,054	2,683,158	193,623	7,596,052	7,115,882	25,852,033
OPERATING EXPENSES														
WITHOUT INC TAX	662,531,282	294,608,054	14,075,775	16,692,674	141,480,879	812,714	80,139,978	74,243,875	862,662	1,973,101	182,193	7,036,238	6,433,035	23,990,103
OPERATING INCOME														
BEFORE INCOME TAXES	147,360,700	76,092,302	3,102,995	3,925,917	29,998,515	335,046	12,327,551	17,496,905	255,392	710,057	11,430	559,814	682,847	1,861,929
TOTAL FEDERAL INCOME TAX	19,062,439	8,745,736	396,841	469,213	4,048,099	8,344	2,072,381	2,398,339	25,162	30,457	4,865	161,785	167,258	533,959
TOTAL STATE INCOME TAX	(3,661,479)	(1,679,865)	(76,225)	(90,126)	(777,552)	(1,603)	(398,059)	(460,669)	(4,833)	(5,850)	(934)	(31,075)	(32,127)	(102,562)
TOTAL OPERATING EXPENSES	677,932,243	301,673,925	14,396,392	17,071,762	144,751,426	819,455	81,814,299	76,181,546	882,990	1,997,709	186,124	7,166,947	6,568,167	24,421,500
TOTAL OPERATING INCOME	131,959,740	69,026,432	2,782,378	3,546,830	26,727,967	328,304	10,653,229	15,559,235	235,063	685,450	7,499	429,105	547,715	1,430,532
ADD: IERCO OPERATING INCOME	6,472,703	2,426,616	91,265	188,356	1,521,085	2,589	976,084	750,186	7,767	10,356	1,942	95,149	85,440	315,868
CONSOLIDATED OPER INCOME	138,432,443	71,453,048	2,873,643	3,735,186	28,249,053	330,893	11,629,313	16,309,421	242,831	695,806	9,441	524,253	633,155	1,746,400
RATES OF RETURN	6.613	7.440	6.594	7.249	6.354	36.111	5.110	6.192	8.788	20.803	1.767	2.951	3.447	2.978
RATES OF RETURN - INDEX	1.000	1.125	0.997	1.096	0.961	5.461	0.773	0.936	1.329	3.146	0.267	0.446	0.521	0.450
AVERAGE MILLS/KWH	53.72	62.77	79.55	37.86	44.47	168.62	33.09	49.66	57.74	104.79	36.89	27.11	26.47	28.44
REVENUE REQUIREMENT CALCULATION														
RATE OF RETURN REQUIRED	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550	8.550
REQUIRED REVENUE	739,757,827	335,467,578	16,561,144	16,635,981	157,935,630	589,825	83,126,625	87,241,794	955,691	1,641,322	214,702	7,461,666	6,557,213	25,368,656
REVENUE DEFICIENCY	66,588,287	17,511,117	1,399,765	1,100,892	16,026,454	(414,683)	12,855,519	10,196,220	(10,800)	(672,939)	59,499	1,633,491	1,539,054	5,364,698
PERCENT CHANGE REQUIRED	9.89%	5.51%	9.23%	7.09%	11.29%	-41.28%	18.29%	13.23%	-1.12%	-29.08%	38.34%	28.03%	30.67%	26.82%
RETURN AT CLAIMED ROR	178,985,602	82,117,553	3,726,118	4,405,644	38,009,378	78,346	19,458,496	22,519,056	236,254	285,977	45,677	1,519,071	1,570,460	5,013,573
EARNINGS DEFICIENCY	40,553,159	10,664,505	852,475	670,458	9,760,325	(252,548)	7,829,183	6,209,634	(6,577)	(409,829)	36,236	994,818	937,305	3,267,173
REVENUE REQUIREMENT FOR RATE DESIGN														
TOTAL IDAHO SALES REVENUES	673,169,540	317,956,461	15,161,379	15,535,089	141,909,176	1,004,508	70,271,106	77,045,574	966,491	2,314,261	155,203	5,828,175	5,018,159	20,003,958
REQUESTED CHANGE IN REVENUE (%)	9.89%	5.51%	9.23%	7.09%	11.29%	-41.28%	18.29%	13.23%	-1.12%	-29.08%	38.34%	28.03%	30.67%	26.82%

Exhibit 304