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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 TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO	))))))	CASE NO. IPC-E-07-08

IDAHO IRRIGATION PUMPERS

DIRECT TESTIMONY

OF

ANTHONY J. YANKEL

DECEMBER 10, 2007

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

1 State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West
2 Virginia.
3
4 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?
5
6 A. I am testifying on behalf of the Idaho Irrigation Pumpers Association, Inc.
7 (Irrigators).
8
9 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?
10
11 A. My testimony will address:
12 • Disproportionate growth on the system
13 • Irrigation Load Research data and curtailment
14 • BPA credit
15 • Irrigation Peak Rewards Program
16 • Irrigation Time-of-Day rates
17
18 Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS IN THIS
19 CASE?
20
21 A. I make the following conclusions and recommendations:
22 • There has been very rapid growth on the system for all customer classes
23 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. Without addressing growth and the cost of growth, all cost of service studies will continue to inappropriately allocate the cost of growth to the Irrigators and away from the customers that are causing these growth related costs. The Irrigators have inappropriately gotten more than the system average increase for at least the last 14 years. Essentially, without recognizing who causes the cost of growth, the cost of service studies to the Commission in this case and previous cases have attempted to spread the cost of growth "equally", thus harming classes that are not growing and benefiting classes that are growing. The Company's cost of service study in this case continues to not allocate the cost of growth to classes that are causing the growth related cost increases on the system.
- 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 twice 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 load research data used in this case for the Irrigators does not reflect the curtailments under the Irrigation Peak Rewards Program. This is an oversight due to the newness of the program. This needs to be corrected in future cases.
- The Irrigation Peak Rewards Program only partially benefits the Irrigators for the significant benefit it provides the rest of the system. There needs to be a significant increase in the level of the curtailment credits paid. An increase of 37 times the existing credits is cost justified.
- The Company has let its Irrigation time-of-day program slip away. As an alternative to the Irrigation Peak Rewards program, an Irrigation TOD program could bring significant benefit to the Irrigators as well as the Company. As opposed to abandoning the TOD program, corrections need to be made to the rates and the time periods involved in order to make the TOD program workable for the benefit of all.

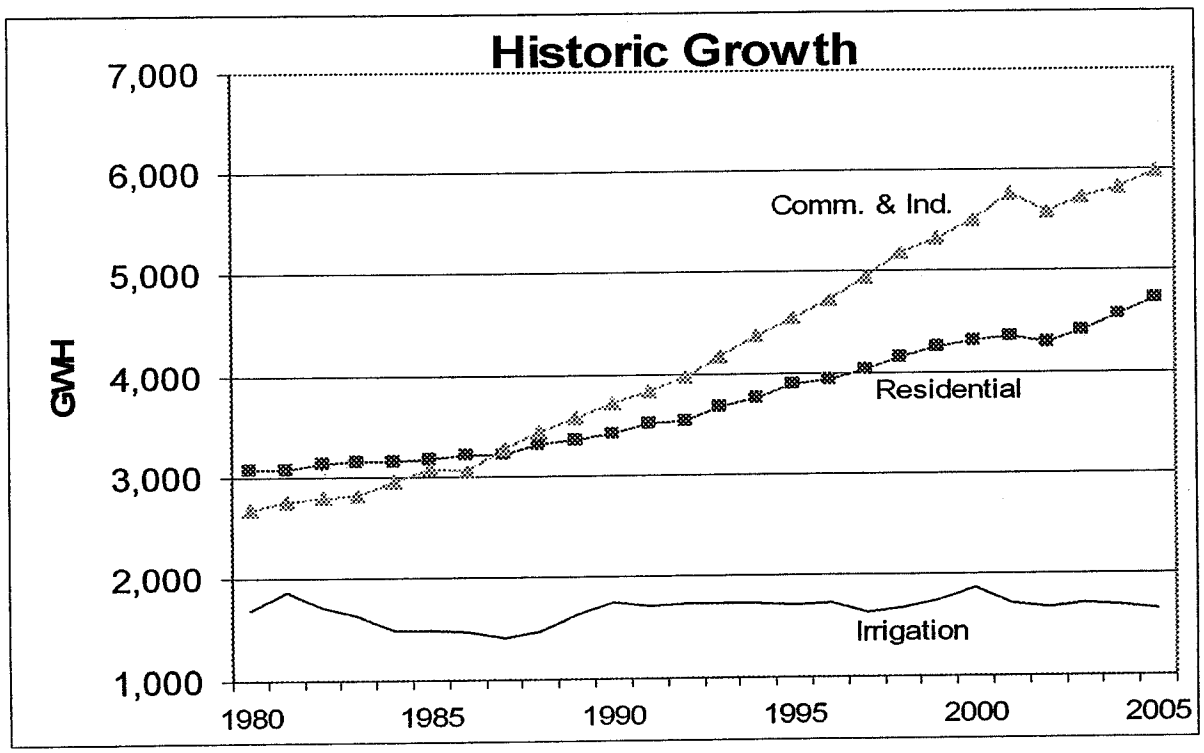
DISPROPORTIONATE GROWTH ON THE SYSTEM

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

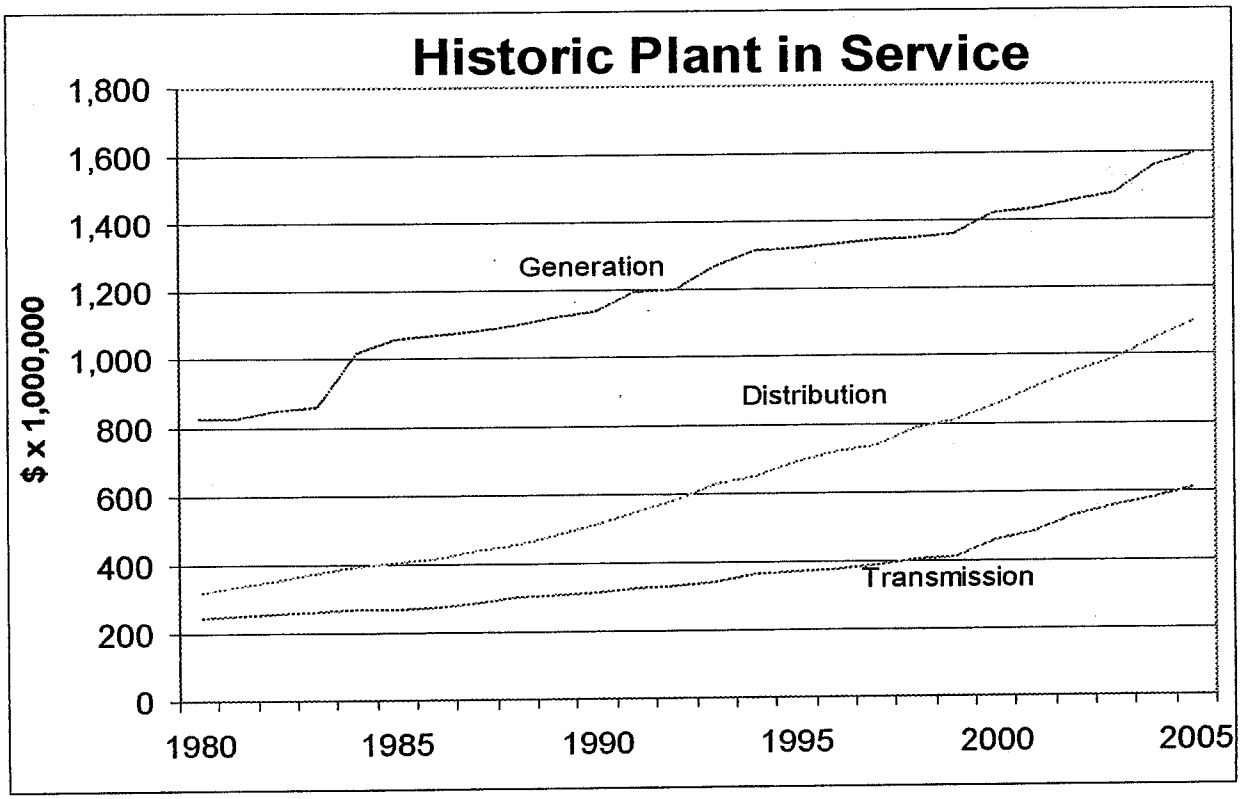
A. No. For more than two decades there has been a major imbalance in the growth on the Idaho Power system between customer classes.

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.
5
6 Q. HAS THIS GROWTH IN LOAD BEEN ACCOMPANIED BY GROWTH IN
7 UTILITY PLANT-IN-SERVICE?
8
9 A. In order to keep up with this growth, there have been significant increases in
10 Plant-In-Service at all functions as demonstrated by the following graph[2]:
11

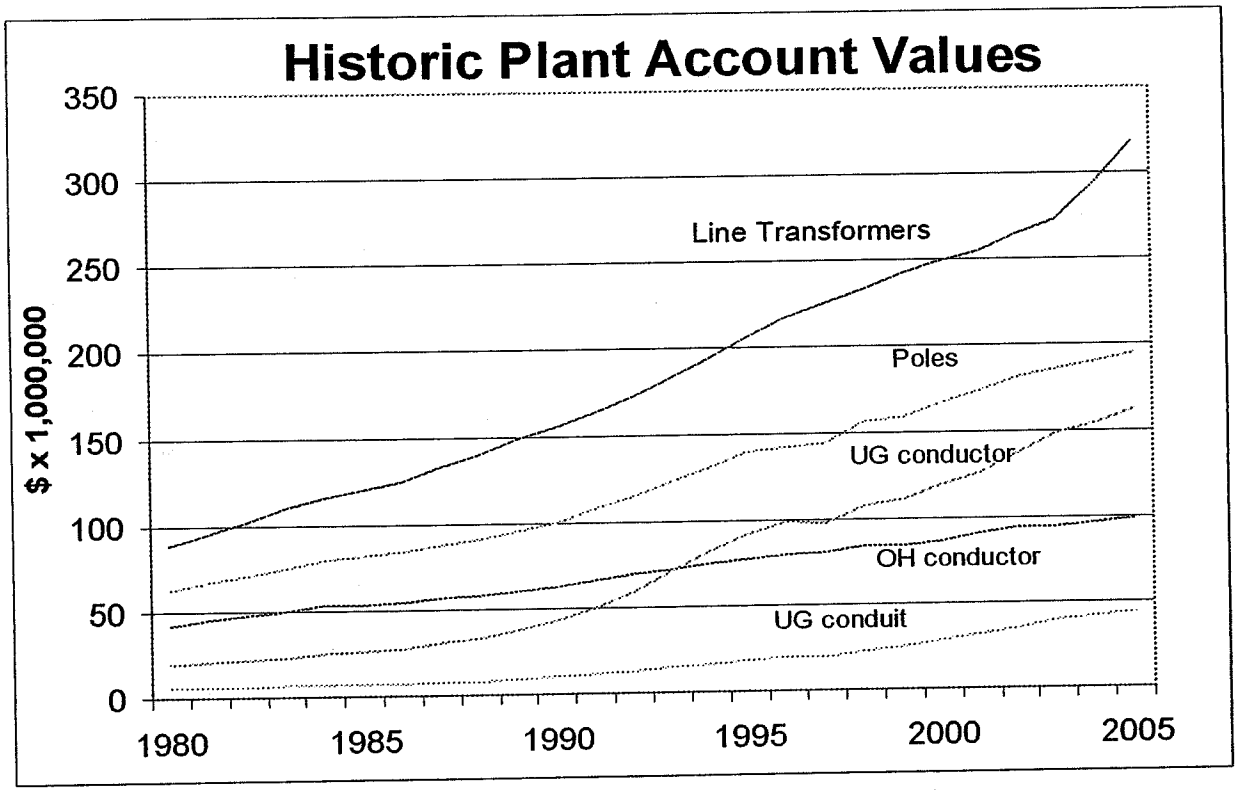


12

[1] Historic usage data taken from pages 25, 27, 29, 31 of Appendix A of Idaho Power's 2006 IRP.

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

[2] Data taken from FERC Form 1 for years 1981-2006.

1 Line Transformer accounts have tripled in the last 25 years. However, the Underground
2 accounts have gone up over 700% of their levels from 25 years ago.
3
4 Q. DOES THE COMPANY'S ALLOCATION METHODS AND COST OF
5 SERVICE STUDIES PROPERLY REFLECT THE IMPACT OF THESE GROWTH RATES
6 ON COSTS TO CUSTOMER CLASSES?
7
8 A. No. Inappropriately, over the last 25 years or so the Company's cost of service
9 studies have allocated a significant portion of this growth to the Irrigation class. Given the
10 obvious fact that growth and the cost of growth is not being fueled by the Irrigators, the
11 allocation of significant portions of the cost of this growth to the Irrigators is on its face counter-
12 intuitive.
13
14 Q. PLEASE FURTHER EXPLAIN HOW THE RESULTS OF THE COMPANY'S
15 CLASS COST OF SERVICE STUDY ARE COUNTER-INTUITIVE.
16
17 A. As pointed out above, the trend that has been in place for more than two decades
18 is that the non-Irrigation load has increased, while the Irrigation load has either stayed even or
19 decreased. Unlike PacifiCorp which has also been undergoing a tremendous amount of growth
20 over the last 20 plus years, Idaho Power has been deemphasizing the 12 CP allocation method
21 and has been focusing on the growth that has taken place during the summer peaks. The

following lists the annual system peak demand that occurs in July data utilized in both this case and Case IPC-E-94-5 which used a 1993 test year[3]:

Annual System Peak	1993	2007	% Change
Irrigation	572,219	609,905	6.6%
Non-Irrigation	1,212,428	2,273,905	87.5%

As can be seem from above, the changes in load at the time of the single annual system peak are striking. Over the last 14 years, the rate of growth for the non-irrigation customers has been at a rate that is approximately 13 times greater than that for the Irrigators.

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

Annual Energy Usage	1993	2007	% Change
Irrigation	1,799,035	1,707,083	-5.1%
Non-Irrigation	8,867,253	13,077,851	47.5%

As can be seem from above, the changes in annual energy usage follow a diverging pattern. Over the last 14 years the Irrigation usage has decreased usage by approximately 5% while Non-Irrigation usage has increased approximately 50%.

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:

[3] The non-irrigation data listed for Case IPC-E-94-5 does not include data for FMC.

Q. What does the continued record growth mean to the level of the Company's expenditures?

A. Both operation and maintenance and capital expenditures have increased in order to enable us to serve our growing customer base and to reinforce our system reliability.

Q. Does the Company project that it will be required to continue to make substantial infrastructure investments over the next three years?

A. Yes. The Company's latest forecast shows construction budgets of approximately $266 million in 2008 and $815 million for 2008 through 2010 combined. Expenditures of this magnitude will enable the Company to develop new resources and sustain those the Company already has, and to build and upgrade transmission and distribution systems required to serve the Company's customers.

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 upon the customers that are causing that growth. Contrary to this premise, the Company's cost of service studies over the last 14 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:

Case No.	Overall Increase	Increase to Irrigators
IPC-E-03-13[4]	17.68%	67.10%
IPC-E-05-28[5]	7.82%	27.03%
IPC-E-07-08[6]	10.35%	42.64%

Clearly, these Company cost of service studies have been produced counter-intuitive recommendations with respect to the Irrigation customers.

[4] Exhibit 41 page 1 line 233
[5] Exhibit 44 page 1 line 53
[6] Exhibit 45 page 1 line 53

1 Q. IS THE ALLOCATION METHODOLOGY IN THE COMPANY'S COST OF
2 SERVICE STUDY IN THIS CASE THE SAME AS THAT FROM 14 YEARS AGO?
3
4 A. Generally speaking, yes. There have been some minor changes from 14 years
5 ago, but the allocation methodology used in this case under Exhibit 43 (referred to by the
6 Company as its "Base Case") is similar for the major allocators (D10, D13, and E10). If
7 anything, the allocation methodology under the Company's Base Case is more tolerant of the
8 lack of Irrigation growth than was the allocation methodology used 14 years ago. In spite of the
9 Company's proposed method in this case being "more tolerant of the lack of Irrigation growth",
10 it is still wide-of-the-mark of fairly allocating the cost of growth to those classes that have been
11 growing.
12
13 Q. HOW DO THE COSTS ALLOCATED TO THE IRRIGATORS AND OTHER
14 CUSTOMERS IN THIS CASE, COMPARED TO THE COST OF SERVICE STUDY
15 PROVIDED 14 YEARS AGO, REFLECT THE LACK OF GROWTH OF THE IRRIGATION
16 CLASS AND THE SIGNIFICANT GROWTH IN OTHER CUSTOMER CLASSES?
17
18 A. A comparison of the level of costs allocated to Irrigators in this case with those
19 allocated 14 years ago, demonstrates the counter-intuitive nature of these studies when growth
20 and the cost of growth is not addressed in the allocation factors. A comparison of the allocated
21 Production rate base between this case (IPCo's "Base Case") and the case 14 years ago reveals
22 the following:

Production[7] (x$1000)	1993	2007	% Change
Irrigation	$164,667	$226,680	37.7%
Non-Irrigation	$847,877	$1,450,689	71.1%

Under the Company's allocation method, the percentage of new Production plant attributed to Irrigators (whose load has been virtually stagnant) is approximately 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 14 years ago reveals the following:

[7] 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 46 (base case), page 3.

Transmission[8] (x$1000)	1993	2007	% Change
Irrigation	$41,271	$ 87,612	112.3%
Non-Irrigation	$207,152	$537,748	159.6%

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 is giving Irrigators 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 14 years ago reveals the following:

Distribution[9] (x$1000)	1993	2007	% Change
Irrigation	$105,394	$183,596	74.2%
Non-Irrigation	$425,080	$988,935	132.6%

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 is giving Irrigators approximate half of the percentage increase in new Distribution plant 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.

[8] 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 46 (base case), page 3.
[9] 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 46 (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.

1 The problem with attempting to develop a consensus was recognized by various participants at
2 the workshop. Although there was general consensus that there was something inherently very
3 wrong with the present allocation scheme as related to its ability to allocate the cost of growth,
4 no one felt that they could go back to their clients and admit that they agreed to a methodology
5 that would cost their client more money—this decision was left to the Commission.
6
7 Q. DOES THE COMPANY'S APPROACH TO RATEMAKING AND COST
8 ALLOCATION ATTEMPT TO REFLECT COSTS?
9
10 A. That is the Company's stated goal, although that may not be the result. The
11 classification and allocation used by the Company, only looks at half of the cost causation
12 equation—it assumes a steady state situation or one with even growth across all classes. The
13 NARUC Electric Utility Cost Allocation Manual makes a general statement that is right on target
14 in this situation:

15 The common objective of the methods reviewed in the following two
16 parts is to allocate production plant costs to customer classes
17 consistent with the cost impact that the class loads impose on the
18 utility system. (emphasis added)[10]
19
20 As a general statement, I believe all parties would agree with this NARUC policy. As
21 demonstrated above, there has been a tremendous amount of growth on the system over the last
22 25 years with associated costs to support that growth. For all practical purposes, the Irrigators
23 have not participated in that rapid growth. However, as has been demonstrated above, the
24 Company's present cost of service studies do not address the disproportionate cost of growth
25 and, thus, do not accomplish this goal.

Q. IS THE COMPANY ADVOCATING THE SAME GENERAL ALLOCATION METHODOLOGY IN THIS CASE AS IT DID OVER THE PAST 14 YEARS?

A. No. Although the Company provided as its Base Case an allocation methodology that is similar to what it has proposed in the past, it is favoring a new classification/allocation method in this case. The results of the Company's Base Case are contained in Mr. Tantum's Exhibit 45. The new method favored by Mr. Tamtum and the Company, classifies/allocates Production costs based upon function (base, intermediate, and peak) during the three summer months. The results of the Company's preferred method are contained in Mr. Tantum's Exhibit 53. The Company is not proposing any changes to its Transmission, Energy, or Distribution allocators. Thus, there is very little overall change.

Q. IS THE NEW ALLOCATION METHOD ADVOCATED BY THE COMPANY FOR PRODUCTION RELATED COSTS AN IMPROVEMENT OVER THE PAST METHOD THAT IT ADVOCATED?

A. No. This method only addresses Production cost and it still suffers from the same shortcomings as the Company's past studies—it allocates costs on a stagnant basis, with no recognition of the impact of growth on costs.

---

[10] 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[11] 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 this case[12]. 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[13]. 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 "forward-looking costs to be incurred in the future" in order to meet growth. Thus, the Irrigators (as well as all classes) get assigned costs, based upon weighting factors designed to reflect

[11] Case No. IPC-E-05-28, witness Brilz at page 19.
[12] Tatum's testimony in this case, page 25, line 10

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

[13] 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 Company's Base Case, but the marginal costs would be tied to the marginal usage and not to the
2 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 THESE
6 COUNTER-INTUITIVE RESULTS DO NOT OCCUR 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 that served as a basis for developing the weighted cost factors
12 can also serve as the source of the data for the forecasted growth as well. In Exhibit 301, I have
13 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[14]. For example, the Company's Exhibit 47 page 1 takes the May normalized demand for
16 the Residential class of 751,370 and multiplies it by a weighting of 14.33 in order to develop a
17 weighted demand of 10,767,135[15]. The original figure of 751,370 is a test year value and not
18 reflective of the growth that will take place on the system. According to the Company's 2006
19 IRP[16], the average load for the Residential class will increase from 4,865,000 to 5,811,000 billed
20 MWh or 19.45% between 2006 and 2016. The Company's billing unit of 751,370 needs to be

[14] 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.
[15] 751,370 x 14.33 = 10,767,135
[16] Idaho Powers 2006 IRP—Sales and Load Forecast page 26.

1 modified in order to reflect the fact that only 19.45% of this figure will be associated with the
2 cost of growth over the next ten years.
3
4 Q. DID YOU PROPOSE THIS MECHANISM AS A MEANS OF REFLECTING
5 THE COST OF GROWTH TO THE WORSHOP IN CASE IPC-E-04-23?
6
7 A. No. The proposal I made to the Workshop was one that looked backward and
8 tried to capture the amount of growth and the cost of growth that took place over the previous 25
9 years. The Workshop was not able to come to an agreement regarding that proposed
10 methodology as a means of properly allocating the cost of growth. The methodology that I am
11 proposing here is forward looking and it match future marginal costs with future growth.
12
13 Q. WHAT GROWTH PERCENTAGES DID YOU INCORPORATE INTO YOUR
14 REVISION OF THE COMPANY'S BASE CASE COST OF SERVICE STUDY?
15
16 A. Based upon the Company's 2006 IRP[17], the following growth percentages were
17 calculated:

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

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

1 I utilized these percentages as the basis for calculating the amount of growth (beyond test year
2 billing determinants) associated with the Generation and Transmission plant (allocators D10,
3 D13, and E10). I made no calculation to reflect the growth in Distribution plant that is larger
4 than the growth in either Generation or Transmission plant.
5
6 Q. WHAT IS THE IMPACT ON THE COMPANY'S BASE CASE COST OF
7 SERVICE STUDY WHEN ITS GROWTH RELATED WEIGHTING FACTORS ARE
8 APPLIED TO FORECAST GROWTH AS OPPOSED TO HISTORIC/PRESENT USAGE AND
9 HOW DO THOSE RESULTS COMPARE WITH THE BASE CASE STUDY IN THE
10 COMPANY FILING?
11
12 A In spite of the fact that this change is only directed at 50% of the allocation factor,
13 as can be seen from Exhibit 302, there is a major difference between the indexed rates of return
14 that result from using weighting factors that are properly aligned with expected growth,
15 compared to the Company's Base Case study that does not link marginal cost weighting factors
16 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	1.346	0.219	0.142	2.564
Company's Base Case	1.315	1.039	0.817	0.295

20 Although the difference between these two cost of service runs is quite large for some rate
21 schedules, it should come as little surprise. It has been well recognized by virtually all parties
22 that the Company's present allocation method does not properly address the cost of growth and

1 the fact that for at least twenty-five years the Irrigators have been getting saddled with costs that
2 they have not placed upon the system.

3 By way of contrast, the Growth Corrected study follows more intuitive logic. The growth
4 on the system over the last two-plus decades has not been even across all classes. Irrigation load
5 has been virtually flat, Residential load has increased rapidly, but not as rapidly as Commercial
6 and Industrial load. Given the growth in average system load[18] of 20.7% that is predicted over
7 the next ten years in the 2006 IRP, any rate group that would be growing less than the average
8 should be getting a smaller share (compared to its size) of the marginal costs, while those
9 growing faster should get a higher percentage. The Irrigation growth is very low and Special
10 Contract growth is less than the average, so this Growth Correction increases the rate of return
11 for those classes over that produced by the Company's Base Case study. Residential growth is
12 about the system average, so there is little impact of using the Growth Corrected method
13 compared to the Company's Base Case. The Commercial and Industrial load growth is above
14 average system growth so the Commercial and Industrial customers rate of return is lowered.
15 Given the fact that the Corrected Growth cost of service run recognizes the link between growth
16 and the growth related weighting factors, the resulting indexed rates of return are quite logical:

17 • The Residential growth rate is somewhat less than the system average; therefore, the
18 indexed rate of return goes up a little when compared to the Normalized study.
19 • The Commercial growth rate is significantly above system average; therefore, the
20 indexed rate of return for Schedule 9 significantly drops when compared to the
21 Normalized study.

[18] 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%.

- 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 Normalized study.
- 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 Normalized study.

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 Plant-in-Service associated with the Distribution system has been greater than both the Generation and Transmission system. A methodology needs to be adopted for addressing the growth on the Distribution system as well. It should be remembered that not only have the Irrigators had very little impact for the past 25-plus years on the cost of the Company's distribution plant, the Irrigators have virtually nothing to do with the costs associated with the Company's Underground Distribution costs.

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 recognized, there is "something inherently troubling with the way costs, associated with growth, [is] 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. 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
05-28	30035	3.20%	3.20%
03-13	29505	5.20%	13.95%
94-05	25880	4.19%	10.23%

1 Over the last 10-plus years, the Irrigators have gotten well over the average rate increase, in spite
2 of the fact that they have not been causing the growth and the need for the rate increases on the
3 system. Based upon the greater than average increases which have been given to the Irrigators in
4 the past and the results of the simple correction/alignment of marginal costs with the growth
5 causing those costs which demonstrates[19] that the Irrigators should be given a 33.8% decrease in
6 rates; I recommend that the Irrigators be given no increase in this case. I recommend that the
7 Residential class be given the average rate increase, and that Schedules 9 and 19 be given larger
8 than average increases.

[19] Exhibit 302 line 43

IRRIGATION LOAD RESEARCH DATA AND CURTAILMENT

Q. DOES THE COMPANY'S LOAD RESEARCH DATA IN THIS CASE EFFECTIVELY CAPTURE THE IMPACT OF THE IRRIGATION PEAK REWARDS PROGRAM?

A. No. Although the Company has made progress in a number of areas regarding the utilization of its load research data, its ability to adequately incorporate the Irrigation Peak Rewards Program (curtailments) into this data is severely deficient. Because the Irrigation curtailments are completely under-represented, the load research data that makes its way to the Company's cost of service studies, significantly over-allocates peak responsibility to the Irrigators. There are three basic areas where this data is deficient:

- The Company is now utilizing the median of the past five years of data to define the monthly coincident load factor for each rate schedule. The Irrigation Peak Rewards Program has not been around that long. Therefore, the use of a 5-year median (although conceptually sound), is not reflective of the results of a rapidly developing program.
- The curtailment customers in the load research data do not represent an acceptable cross-section of those participating in the program, and ultimately, under-represent the curtailments taking place.
- As it turns out, some of the customers in the load research sample that were involved in the curtailment program in 2006 were (for some reason) not interrupted at various times; thus, under-valuing the impact of the curtailment that should have taken place.

Q. HOW DOES THE FACT THAT THE CURTAILMENT PROGRAM HAS NOT BEEN IN EXISTENCE FOR FIVE YEARS IMPACT THE WAY THAT THE COMPANY DEVELOPS ITS COINCIDENT PEAK DEMAND DATA?

A. The Company has recently adopted a procedure where it uses the median monthly load factors from the previous five years of load research data in order to derive its normalized monthly peak demands for cost allocation purposes. I fully agree with this approach, except in the case where there are known changes to the overall data being collected. The introduction of, and increasing participation in, the Irrigation curtailment program will greatly skew the monthly coincident load factor data being collected. The data from 2006 should represent an entirely different situation than that from 2002 when the Peak Rewards program did not exist.

Q. PLEASE EXPLAIN WHY THE CUSTOMERS IN THE COMPANY'S LOAD RESEARCH DATA DO NOT REPRESENT AN ACCEPTABLE CROSS-SECTION OF THOSE PARTICIPATING IN THE CURTAILMENT PROGRAM.

A. The Company's response to IIPA Request 3-3 states:

> The company does not have a statistical load research sample specific to Schedule 23. However, to monitor and spot-check the performance of the Irrigation Peak Rewards Program, some interval meters were installed. ... Since these meters are not part of a statistical sample, stratum weighting factors do not apply.

Out of the 145 Irrigators in the Company's load research study, the Response to IIPA Request 3-1 lists 21 load research customers as being on the curtailment program. Two of these 21 customers had no energy listed during any hour of the curtailment timeframe: June, July, and

August. The following depicts how these 19 sampled customers were curtailed each day of the week and how large their combined load was:

	Customers	MW
Monday	2	0.2
Tuesday	10	6.4
Wednesday	2	0.4
Thursday	6	2.4
Friday	3	1.9

According to the Company's 2005 report[20] on its Irrigation Peak Rewards program, the scheduled curtailments on Tuesdays, Wednesdays, and Thursdays was approximately 2.5 times greater than that scheduled for Monday's and Fridays. It is obvious from a review of the above load research data that the 19 sample customers were not representative of this overall distribution of the curtailments that took place by day of the week.

Of even more concern is the fact that during June the system coincident peak occurred on a Tuesday, but it occurred on a Monday for both July and August. For all practical purposes, there was essentially zero representation of participating load curtailment in the load research data for Mondays. It is not that load was not curtailed on these Mondays, it is that the load research data does not reflect what was curtailed.

Q. YOU INDICATED THAT SOME OF THE CUSTOMERS IN THE LOAD RESEARCH SAMPLE THAT WERE INVOLVED IN THE CURTAILMENT PROGRAM IN 2006 WERE (FOR SOME REASON) NOT INTERRUPTED AT VARIOUS TIMES; THUS, UNDER VALUING THE IMPACT OF THE CURTAILMENT THAT SHOULD HAVE TAKEN PLACE. PLEASE ELABORATE.

[20] December 1, 2005 Irrigation Peak Rewards program page 11, Table 6

1

2 A. There are instances[21] in both the load research data and the Schedule 23 load

3 profile data where customers should have been curtailed, but the data does not show a

4 curtailment. For example, load research customer 62400025 was supposed to be curtailed on

5 Tuesdays, but had a load of 366 kW during the hour of the June coincident peak. The data

6 demonstrates that this customer is normally curtailed on Tuesdays, but for some reason or other

7 there is usage data listed during the time of this monthly coincident peak when there should have

8 been a curtailment.

9

10 Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS REGARDING THE

11 GATHERING AND USAGE OF LOAD RESEARCH DATA FOR THE IRRIGATION CLASS

12 IN THIS CASE?

13

14 A. Generally, I believe the Company has been working hard to collect reliable load

15 research data. However, the Irrigation Load Curtailment program is a new twist that will need

16 better scrutiny in the future in order to extract reliable data. I point out the above problems so

17 that they can be addressed before the Company's next case and to add support to my proposal

18 that the Irrigators be given no increase in this case.

[21] See the Company's Response to IIPA 3-3

BPA Credit

Q. WHAT IS THE IMPACT OF THE RECENT LOSS OF THE BPA CREDIT ON THE IRRIGATION CUSTOMERS?

A. According to the Company, the BPA credit for Irrigators[22] in 2006 filing was $1,917,264. By comparison, the revenue from Schedule 10 was only listed[23] as $70,750,659. Thus, the Irrigators effectively paid only $68,833,395[24]. Absent any increase in this case to the Irrigators, their effective rate will jump $1.9 million or 3% above what they have been paying. Although such a rate increase may appear to be small, it is an additional cost burden that Irrigators will be facing. The Residential class has also lost its BPA credit[25] of $16,246,281. Out of a total revenue of $294,087,612 in 2006, the Residential customers effectively paid $277,841,331. Thus, the Residential customers are facing an approximate 6% increase, absent anything that happens in this case.

Although these losses cannot be directly off-set in this case, the Commission needs to establish cost-effective ways for customers to help themselves and the Company better control overall costs. For the Irrigators, the best way to accomplish this would be to put in place an effective Peak Rewards program and/or an effective time-of-day rate.

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[22] Company Response to IIPA Request 4-2
[23] Company Exhibit 58, page 1
[24] $70,750,659 - $1,917,264 = $68,833,395
[25] Company Response to IIPA Request 4-3

IRRIGATION PEAK REWARDS PROGRAM

Q. ARE THE IRRIGATORS SUPPORTIVE OF THE COMPANY'S IRRIGATION PEAK REWARDS PROGRAM?

A. Yes. The Irrigators have been very supportive of this program as well as the one offered in the PacifiCorp service area that interrupts electricity to irrigation pumps during the summer super-peak hours. The Irrigation Peak Rewards Program is a workable program that produces tangible benefits for the Company as well as all ratepayers.

Q. DO THE IRRIGATORS FULLY AGREE WITH HOW THE IRRIGATION PEAK REWARDS PROGRAM IS BEING IMPLEMENTED?

A. No. Although the Irrigators are very supportive of the program in general, there are a number of areas where the Irrigators believe that substantial improvements can be made. The Irrigators believe that a general rate case is an appropriate time and place to review matters related to specific rate schedules such as the Company's Schedule 23.

Q. PLEASE GIVE A BRIEF OVERVIEW OF THE EXISTING IRRIGATION LOAD CONTROL PROGRAM ON THE IDAHO POWER SYSTEM.

A. At present Schedule 23 is the main DSM type vehicle for Irrigators which consists of fixed/pre-scheduled times and days for interruptions of Irrigation load. Under Schedule 23,

Irrigators are interrupted for 4-hours on either 1, 2, or 3 days per week during the months of June, July, and August. The present monthly credits are as follows:

1 day per week	$2.01 /kW month
2 days per week	$3.36/kW month
3 days per week	$4.36/kW month

The total annual credit (assuming that an Irrigator operates each of the three months) is:

1 day per week	$ 6.03 /kW-year
2 days per week	$10.08/kW-year
3 days per week	$13.08/kW/-year

Q. HAS THE IRRIGATION CURTAILMENT PROGRAM UNDER SCHEDULE 23 ENJOYED A GREAT DEAL OF SUCCESS?

A. Success is a relative measure. According to the Company's July 23, 2007 press release, there was a reduction of 40 MW during the Fourth of July holiday when temperatures reached triple digits. This level of curtailment may seem significant, but when compared to the Irrigator's 2007 projected contribution to the July system peak of over 600 MW, this 40 MW seems small. Although there may be a number of factors causing this program to only produce a relatively small reduction in peak load, these factors generally boil-down to a simple question of economic incentive.

It should be noted that this 40 MW's is the same figure mentioned in the Company's 2006 IRP[26] regarding the reduction in peak load during 2005—suggesting that there has not been a major change in participation since its first year of operation in 2005. However, there was an increase in some of the participation credits between 2005 and 2007. For example, the credit for the 1-day/week option stayed the same at $2.01/ kW, but the 2-day/week option credit increased

1 from $2.52/kW up to $3.36/kW (an increase of 33%), and the 3-day/week option credit increased
2 from $2.76 up to $4.36/kW (an increase of 58%).
3 Two things should be gleaned from this credit and curtailment information. First, the
4 impact of the program was low in the program's first year of operation (2005) with 40 MW of
5 peak reduction occurring and that impact has changed little with a reported 40 MW (out of 600
6 MW of Irrigation load) of system reduction in 2007. The Irrigation Peak Rewards program can
7 be a great benefit to the system, its customers, and to the Irrigators. However, it is being
8 underutilized. The level of the credit (economic incentive) is the primary reason for this lack of
9 participation.
10 Second, even assuming that the credit for the 1-day/week option is appropriate, the
11 increases of 33% and 58% to the 2-day/week and 3-day/week options were completely
12 inadequate to reflect an appropriate credit for these multiple day options. If an Irrigator should
13 be paid $2.01 for curtailing 1 kW of demand 1-day per week, he should be paid <u>at least twice</u>
14 <u>that amount</u> if he curtails twice as often. It should be "at least twice that amount" because there
15 are no further hardware, installation, administrative, or other costs getting the Irrigator to be
16 interrupted on 2-days/week as opposed to just 1-day/week. This cost savings should be passed
17 on as an additional incentive in order to get more participants. However, instead of being offered
18 a credit of $4.02/kw for interruptions on 2-days/week, the Company offers only $3.36/kW. The
19 3-day/week option credit is even worse (in spite of the 58% increase that it has received since
20 2005). The 3-day/week option offers three times the interruptions as the 1-day per week option
21 and so it should have a credit of at least $6.03/kW. However, the Company is only offering a
22 credit of $4.36/kW. One needs to ask why any customer would opt for being curtailed on

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[26] Appendix B-Demand Side Management 2005 Annual Report, page 9.

1 multiple days when the amount of credit per curtailment decreases. The present credit structure
2 represses, as opposed to promotes, additional participation.
3
4 Q. IS THE PRESENT CREDITS LISTED UNDER SCHEDULE 23 FOR THE 1-
5 DAY/WEEK OPTION APPROPRIATE?
6
7 A. No, from two perspectives. First, as demonstrated above, although there have
8 been increases in the level of the credit paid, participation (as measured by overall curtailment) is
9 not strong. Basically, there is an interest in the program on the part of the Irrigators, but they are
10 either finding a cost/benefit ratio that is very low or one where costs exceed the benefit (credit).
11 From a policy standpoint, it makes little sense to offer programs that have only marginal or no
12 benefits to the customers.
13 Second, in a recent report regarding DSM Resources that was prepared for PacifiCorp, it
14 was demonstrated that the benefits of the Irrigation Load Curtailment program (mostly in its
15 Idaho service area) far exceeds the costs associated with that program (even under the Report's
16 assumption of a $20 per year credit being paid). From a policy standpoint, it is inappropriate to
17 have a DSM type resource with such a large advantage to the system being under utilized by the
18 customers because the credit being paid is such a small fraction of the benefit being realized.
19
20 Q. PLEASE ELABORATE ON THIS DSM REPORT FOR PACIFICORP.
21
22 A. On July 11, 2007 Quantec issued its Report to PacifiCorp entitled
23 "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other

Supplemental Resources". This Report was designed to (and virtually did) cover all aspects of DSM or alternative resources. Relevant pages regarding the Irrigation Curtailment program are contained in Exhibit 303. The Irrigation Load Curtailment program was viewed as one of only three "firm" DSM options that represent a Class 1 resource. Of these three Class 1 options, the Irrigation Load Curtailment program had the 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 a levelized cost of $47/kW-year (based upon a $20/kW-year credit) compared to 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. Based upon Lamont Keen's testimony in this case (page 4), IPCo is pursuing the addition of the following resources:

	$/kW-month[27]	$/kW-year
170 MW Simple Cycle CT	$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

[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 Based upon these options that IPCo is pursuing, the $98/kW-year figure is a good representation
2 of the avoided cost of a program like the Irrigation Peak Rewards program.
3
4 Q. WHAT HAS BEEN THE COST OF THE IRRIGATION PEAK REWARDS
5 PROGRAM?
6
7 A. There has been very little information published regarding IPCo's program by
8 comparison to the annual reports produced by PacifiCorp regarding its program. IPCo's 2006
9 IRP indicates[28] that in the first full year of operation (2005) that $1,468,000 was spent and 40.3
10 MW of summer peak demand was saved. Of this amount $479,484 was associated with program
11 costs (equipment, installation, advertising, and administrative), while the remainder was paid out
12 in incentives/credits.
13 In spite of the fact that the first-year costs would have included a number of start-up and
14 non-reoccurring costs, the program costs (not including incentive/credit payments) of $479,000
15 worked out to only $11.89/kW-year[29] of summer peak demand savings. Effectively, this leaves
16 another $86/kW-year ($98 - $12 = $86) of avoided cost savings that could be used as credits to
17 pay Irrigators for the benefit they provide to the system and to induce significantly more
18 participation.
19 The total cost[30] of the incentive paid in 2005 to obtain this 40.3 MW reduction in summer
20 peak demand was $988,798, which averages out to $24.54/kW-year[31] of peak reduction realized.
21 Note, this incentive cost of $24.54/kW-year is the overall incentive paid to get 40.3 MW of

[28] 2006 IRP, Appendix B, page 53
[29] $479,494 / 40.3 MW / 1000 = $11.89/kW
[30] From the 2006 IRP, Appendix B, page 53, total utility costs of $1,468,282 less the total resource cost of $479,484 yields an incentive amount of $988,798.

actual peak reduction, while the actual incentive paid out to individual customers is $6.03/kW-year. In other words, the Company is paying approximately four Irrigators $6.03/kW-year ($24.18/kW-year in total) in order to get one kW of actual peak reduction.

Q. HOW MUCH COULD THE IRRIGATION LOAD CURTAILMENT CREDIT BE INCREASED BEFORE THE COST OF THE PROGRAM WOULD EQUAL THE MINIMUM CAPACITY VALUE OF THESE INTERRUPTIONS?

A. Presently the Company is paying out $24.54/kW-year in order to obtain a reduction of 1 kW of peak. With the minimum headroom of $86/kW-year, a credit that is 3.5 times larger[32] than the present credit could be justified.

Q. WHAT LEVEL OF CREDIT DO YOU RECOMMEND IN THIS CASE?

A. It is clearly a loss to the system (and to the Irrigation customers in particular) to have less than 10% participation[33] in a program that provides a savings of at least $98/kW-year, but only costs the Company less than $12/kW-year plus a credit payment. I recommend that this credit be increased so as to bring the cost of the Irrigation Peak Rewards Program up to at least $98/kW-year. Depending upon acceptance of the program after this case and the gathering of additional data, it may be necessary to adjust this credit upward at a later date.

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[31] $988,798 / 40.3 MW / 1000 = $24.54/kW-year
[32] $86 / $24.54 = 3.5
[33] On page 5 of the Company's report on its 2005 Irrigation Peak Rewards Program, it lists 893 participating service points. Company Exhibit 59 page 13 indicates that there were 62,675 in-season bills for an average number of bills during 5 months of 12,535. Therefore 7.1% of the average number of service points participated in 2005.

1 With respect to designing the rate, I will start with the assumption that all Irrigators are
2 on the 1-day/week option. Because the Company does not expect an equal chance of the peak
3 occurring on each day of the week, it has spread the curtailable load in a manner that presumably
4 reflects its anticipation of peak load. Given the manner in which Schedule 23 customers are
5 spread across the days of the week[34], it would take 3.84 kW of curtailable load to get 1 kW of
6 summer peak savings. Thus, this $86/kW of summer peak savings/credit would need to be
7 spread over 3.84 kW of participating load or $22.40/kW of curtailable load ($86 / 3.84 =
8 $22.40). I recommend that this $22.40/kW credit be applied for the season as opposed to over
9 the individual months.
10
11 Q. WHAT CREDITS DO YOU RECOMMEND FOR THE 2-DAY/WEEK AND 3-
12 DAY/WEEK CURTAILMENT OPTIONS?
13
14 A. Because the 2-day/week option produces twice the curtailable load as the 1-
15 day/week option, that credit should be twice this amount or $44.80/kW. Likewise, the 3-
16 day/week option should have a credit of $67.20/ kW. The Company has justified paying 2-
17 day/week option customers less than twice the credit paid 1-day/week customers on the concern
18 that there could be "free-riders" associated with customers that opt for interruptions more than
19 one day per week. In this case, a "free-rider" is considered to be someone that would not be
20 operating absent the program and thus, the credit would be paid with no true curtailment benefit
21 going to the Company. I do not share the level of concern the Company has with free-riders.
22 Furthermore, I do not believe the way to address a free-rider problem is to price all multiple day

[34] According to Table 6 on page 11 of the Company's 2005 report on its Irrigation Peak Rewards program, Tuesdays, Wednesdays, and Thursdays get allocated approximately the same level of curtailable load.

1 curtailment customers less than the multiple benefit that they provide when the concern
2 regarding free-riders would only represent a fraction of the customers.
3
4 Q. DO YOU HAVE A RECOMMENDATION THAT WOULD BETTER
5 ADDRESS THE COMPANY'S FREE-RIDER CONCERNS, WHILE NOT PENALIZING ALL
6 THE CUSTOMERS THAT OPT FOR MULTIPLE DAYS OF CURTAILMENT?
7
8 A. Yes. I make this recommendation for all credits that are greater than the 1-day
9 credit of $22.40/kW.
10 It can be calculated[35] from Company Exhibit 59, page 13 that the average, in-season load
11 factor for the Irrigators is 50.25%. If a customer that is on a multi-day option has a load factor
12 less than this class average, an adjustment could be made to reflect the fact that he has more
13 times when he is not operating and thus a higher potential for being a free-rider. For example, if
14 a customer on a 2-day curtailment option has an average seasonal load factor of only 25.13%
15 (half that of the Irrigators as a whole), then he should get half the credit for the second day of
16 curtailment, i.e., he should get a $22.40/kW credit for the first day plus $11.20/kW for the
17 second day of curtailment. If a customer is on a 3-day curtailment option and only has a
18 seasonal load factor of 25.13%, then he should get full credit for the first day and only half of the
19 credit for the second day and half for the third day of curtailment. Effectively, the customer on
20 the 3-day curtailment option gets the same credit as a customer on a 2-day curtailment option,
21 which is fair because he has half of the load factor, but is offering twice the curtailment above
22 the 1-day curtailment option.

---

while Mondays and Fridays get approximately 42% of this amount.
[35] 1,109,400,571 in-season kW / (3,025,809 kW / 5 months) / 152 days / 24 hours = 50.25%.

1

2 Q. WHY ARE YOU NOT APPLYING THIS LOAD FACTOR ADJUSTMENT TO

3 THE 1-DAY CURTAILMENT OPTION?

4

5 A. The only way it would be fair to apply this load factor adjustment to the 1-day

6 curtailment option would be if it was symmetrical, i.e., it would have to be applied as a penalty

7 to those with average seasonal load factors below 50.25% and as a benefit to those with average

8 seasonal load factors above 50.25%. I believe this would be overly complicated and confusing

9 to the customers. I only proposed this load factor correction to address the Company's free-rider

10 concerns regarding customer choosing multi-day curtailment options that may in fact be free-

11 riders.

12

13 Q. DO YOU HAVE ANY PROPOSED CHANGES TO IPCO'S PEAK REWARDS

14 PROGRAM IN ADDITION TO THE INCREASE IN THE LEVEL OF THE CREDIT?

15

16 A. Yes. If the curtailment credit is going to be increased up to a level that reflects

17 the true marginal cost of capacity, then I recommend that the curtailment period be expanded

18 from the present three summer months to include the entire five months of the Irrigation season.

19 The Company's various marginal cost studies and its 2006 IRP point to capacity deficiencies in

20 all five months of the Irrigation season—not just June, July, and August. If the credit to

21 Irrigators would not be set at the true levelized value of the benefit provided, then it would not be

22 appropriate to increase the period over which curtailments could take place.

23

Q. ARE THERE OTHER CHANGES YOU WISH TO PROPOSE TO THE PEAK REWARDS PROGRAM?

A. Yes. At present IPCo limits participation in the Peak Rewards program to Irrigators with at least 75 horsepower. This greatly limits the number of customers that can participate and prevents all but the largest Irrigators from participating. In the past IPCo has justified its 75 horsepower limit on the basis that the installation costs do not justify the installation of such equipment on smaller customers. Contrary to this, PacifiCorp's program has no horsepower restriction. I recommend that participation in IPCo's Peak Rewards program be put on a par with that of PacifiCorp's by removing the present horsepower limit and including the same language as found in PacifiCorp's Schedule 72, Sheet 72.4, paragraph 8:

> Cost of Control Devices. The participation Customer shall pay the cost of timers or other load control devices and associated installation. Such costs include, but are not limited to, direct and indirect costs of load control devices, labor, and material and equipment required to achieve scheduled load control events. The participating Customer shall pay such cost only to the extent that they exceed one thousand dollars per meter. Customers required to pay the cost of control devices under terms of this Special Condition will be provided a statement detailing such costs.

Q. PACIFICORP HAS STARTED A NEW "COMPANY OPTION" CURTAILMENT PROGRAM AS OPPOSED TO JUST THE DESIGNATED DAY PROGRAM THAT IT AND IDAHO POWER HAVE BEEN OPERATING IN THE PAST. DO YOU HAVE ANY RECOMMENDATIONS WITH RESPECT TO SUCH A PROGRAM FOR IDAHO POWER?

1 A. From everything that I have been able to gather, this "Company Option" program
2 that is being conducted by PacifiCorp is both a hit with the Company as well as the Irrigators that
3 are participating. We should get a report back on this new option late this fall. I recommend
4 that PacifiCorp's report on this option be reviewed closely by Idaho Power, the Commission
5 Staff, and the Irrigators with the intention (if all goes well) of implementing a similar program or
6 at least a pilot program in the Idaho Power service area for the summer of 2008.
7
8 Q. THE IRRIGATORS AND PACIFICORP STIPULATED TO A NUMBER OF
9 DIFFERENT CONDITIONS AND RATES IN PACIFICORP'S RECENT RATE CASE.
10 SOME OF THE RATES THAT ARE IN THAT STIPULATION ARE LOWER THAN WHAT
11 YOU PROPOSE HERE. WHY SHOULD THE COMMISSION ADOPT THE HIGHER
12 RATES THAT YOU ARE PROPOSING IN THIS CASE?
13
14 A. The rates to which the Irrigators agreed in the PacifiCorp case were a part of a
15 package. That package contained the Company Option curtailment package that I mentioned
16 above. That package does things like give the Irrigators less curtailments than what is offered
17 here as well as the ability to opt-out of five curtailments throughout the year. The credit for the
18 Company Option package is higher than what is recommended here for a 1-day curtailment
19 option. Basically, the Irrigators were happy with the entire package they got in the PacifiCorp
20 rate case, and would be happy with the same package in this case. However, it would be
21 completely inappropriate to take only pieces of the PacifiCorp stipulation and assume they can
22 be applied with any validity in this case.

Irrigation Time-Of-Day Rate

Q. DOES IDAHO POWER HAVE EXPERIENCE WITH VOLUNTARY TIME-OF-DAY RATES?

A. Yes. There has been a limited program for both Residential and Irrigation customers. However, in my opinion these Time-of-Day (TOD) rates are not producing desired results and the Irrigation TOD Schedule 25 has been abandoned as of October 1, 2007.

By contrast, PacifiCorp in Idaho seems to have had a great deal of success with its Residential TOD program in Idaho. There has been a Residential Time-Of-Day (TOD) rate schedule (Schedule 36) in Idaho for the last 20 years. It has been more successful than many TOD rate schedules. In PacifiCorp's current rate case there are 16,276 Residential customers on Schedule 36 out of a total of 54,047 total Residential customers. Approximately half (47%) of the Residential usage takes place on Schedule 36. Schedule 36 contributes less to the system peaks as demonstrated by the fact that its contribution to the 12-coincidents peaks is only 43% of the overall Residential contribution.

It is noteworthy that even during the summer months (when there is no alternative to air-conditioning) that the relative usage between super-peak hours (2:00 p.m. to 8:00 p.m.) and average usage for Schedule 36 customers is less than that for larger Schedule 1 customers that have air-conditioning potential[36]. Basically, Schedule 36 customers are shifting a portion of their usage from the super-peak to other times.

It is noteworthy to contrast PacifiCorp's Residential TOD program with that of Idaho Power's Schedule 5 which is limited to one geographic area with AMR metering. There are only

1 86 TOD customers taking service under this program[37]. Even for the limited availability area in
2 which Schedule 5 is offered, this is a very low participation rate.
3
4 Q. TO WHAT DO YOU ATTRIBUTE THE SUCCESS OF PACIFICORP'S
5 RESIDENTIAL TOD RATE IN IDAHO?
6
7 A. Like any program or rate schedule, there are a variety of things that contribute to
8 the success of PacifiCorp's Schedule 36 compared to Idaho Power's Schedule 5 or Schedule 25.
9 Historically, standard Residential rates in PacifiCorp's Idaho service area have been higher than
10 comparable rates in the Idaho Power service area—higher rates make alternative rate designs
11 more attractive. According to the 2006 FERC Form 1's, PacifiCorp's non-TOD Residential
12 Schedule 1 customers paid an average of 8.39 cents/kWh, while Idaho Power's non-TOD
13 Residential Schedule 1 customers paid an average of 5.97 cents/kWh.
14 Of more significance is the differential in rates between on-peak and off-peak hours. If
15 this differential is not sufficiently large, there is little incentive to shift usage from on-peak hours
16 to off-peak hours. PacifiCorp's Schedule 36's summer TOD rates[38] are simply 10.8 cents/kWh
17 on-peak, and 3.7 cents/kWh off-peak, for a differential between on-peak and off-peak of 7.1
18 cents/kWh.
19 Idaho Power's Schedule 5's summer TOD rates are more complex with three tiers (on-
20 peak, mid-peak, and off-peak), but one can readily see the differences between this rate and
21 Schedule 36. Schedule 5's highest priced, on-peak rate (1:00 p.m. to 9:00 p.m.) is 8.3

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[36] Schedule 1, Stratum 3 customers average usage was 1,276 kWh in June, 1,396 kWh in July, 1,243 kWh in August, and 1,165 kWh in September.
[37] Company Exhibit 59, page 1
[38] All rates in this section of testimony have been round to one decimal point for easy of reading.

1 cents/kWh. This "highest rate" is 2.5 cents/kWh less than the Schedule 36 on-peak rate and is
2 almost as large as the entire differential of 7.1 cents/kWh in Schedule 36. Schedule 5's lowest
3 priced, off-peak rate (9:00 p.m. to 7:00 a.m.) is 4.5 cents/kWh. This "lowest rate" is almost a
4 penny more than the off-peak rate in Schedule 36. Schedule 5's mid-peak rate (7:00 a.m. to 1:00
5 p.m.) is 6.1 cents/kWh. This mid-peak rate essentially dampens any differential between the
6 high and low cost hours—it is essentially a neutral time.
7 It is important to remember that PacifiCorp's Schedule 36 and Idaho Power Schedule 5
8 are voluntary/optional rates. Schedule 36 offers customers a significant choice differential and is
9 successful. Idaho Power's Schedule 5 offers significantly less difference between on-peak and
10 off-peak rates and the participation rate reflects this fact.
11
12 Q. HOW DO PACIFICORP'S SCHEDULE 36 RATES COMPARE WITH TOD
13 RATES BEING DEVELOPED TODAY?
14
15 A. According to the Pacificorp's "Assessment of Long-Term, System-Wide Potential
16 for Demand-Side and Other Supplemental Resources" study, the new TOD rates being
17 developed are more inverted than those being offered in Schedule 36. On page 46 of that Report,
18 it is stated:
19 The TOU [TOD] rates developed in recent years typically differ from those of the
20 past in several important ways. First, most new TOU rates contain three price
21 tiers as opposed to the two-tier rates common in many long-standing TOU
22 programs, including those offered by PacifiCorp. This allows utilities to set high
23 prices during their highest peak periods and offer exceptionally low off-peak
24 prices overnight when the cost is at its lowest and supply is plentiful. The
25 majority of hours are assigned a "mid-peak" price that is typically a slightly
26 discounted version of the standard rate. Another change is that the duration of the
27 peak period is typically shorter than in the past. Finally, the price differentials
28 between peak and off-peak prices tend to be greater than in the past to encourage

load shifting away from the peak period. For long-standing TOU rates, this differential averaged about 7.6 cents/kWh, whereas newer programs tend to have a differential of greater than 10 cents/kWh. For comparison, PacifiCorp's existing TOU rates offer a price differential of roughly 4.5 cents/kWh to 7.5 cents/kWh, depending on the operating utility and the season.

Q. HOW DID IDAHO POWER'S IRRIGATION TOD RATE (SCHEDULE 25) COMPARE WITH PACIFICORP'S SUCCESSFUL RESIDENTIAL TOD PROGRAM?

A. Like its Residential TOD rate, Schedule 25 had three rate periods with very little differential between the on-peak rate of 6.2 cents/kWh and the off-peak rate of 1.8 cents/kWh. Instead of a differential that approached and/or exceeded 10 cents/kWh, the rate differential was only 4.4 cents/kWh. A second problem with Schedule 25 was the length of time for each of the time slots. An Irrigator is generally a customer with one piece of equipment that can either be turned on or off. Portions of the load cannot be shifted, either the entire load is shifted or none of it is shifted. As a result, the off-peak period which is an award time is way too short at only 12 hours every day (including weekends and holidays), and the super-peak timeframe is way too long at 8 hours every day.

Q. HOW CAN THIS INFORMATION BE USED TO DEVELOP A TOD RATE FOR IRRIGATION CUSTOMER?

A. A TOD rate for Irrigators is an opportunity to not simply lower the costs to the Irrigators, but to lower the overall system costs as well. Like Schedule 36, a TOD rate for Irrigators should get its own cost-of-service treatment such that the rates and benefits stand on their own.

1 TOD rates (as an option and not mandatory) could be a feasible alternative for many
2 Irrigation customers. However, Irrigators can not be realistically expected to follow a similar on-
3 peak pattern as Residential customers. Instead, I recommend that something more like a super-
4 peak price be developed in conjunction with an off-peak price. For the super-peak timeframe, I
5 recommend the same 5-days per week as in the Irrigation Curtailment program and the same 4-
6 hours per day (4:00 p.m. until 8:00 p.m.).
7 I recommend that the super-peak price be set at 15 cents/kWh and that the off-peak price
8 be set at 4.2 cents/kWh. These rates have been chosen in order to develop a spread of over 10
9 cents/kWh between the super-peak and the off-peak and in order to remain revenue neutral if
10 there is no net change in consumption patterns.
11
12 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
13
14 A. Yes.

Exhibit No. 301
Case No. PAC-E-07-05
Anthony J. Yankel
"IIPA and Idaho Power Company Development of Weighted Demand and Energy Allocators, Based on Growth For The Twelve Months Ended December 31, 2007"
10 pages

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS, BASED ON GROWTH
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

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)	Month
CAPACITY RELATED ALLOCATION FACTORS										CAPACITY RELAT
Monthly Coincident Demands @ Generation Level										Monthly Coincident
January		2,210,437	1,193,549	36,884	49,136	490,137	1,298	286,265	1,031	January
February		2,250,001	1,201,564	38,337	50,741	512,824	323	296,694	1,334	February
March		2,017,048	1,027,500	32,203	49,326	475,629	0	281,005	7,382	March
April		1,823,237	807,559	26,757	48,623	431,261	0	282,639	84,561	April
May		2,247,643	751,370	34,722	56,717	522,850	0	315,886	427,281	May
June		2,752,148	902,106	47,867	58,891	587,087	0	320,269	698,440	June
July		2,883,810	1,065,895	52,458	63,257	603,494	0	345,202	609,905	July
August		2,708,910	1,030,939	43,392	61,072	577,905	0	323,835	528,095	August
September		2,426,855	859,348	39,344	66,129	540,273	0	312,115	470,243	September
October		1,777,799	787,609	24,130	55,098	403,060	0	299,455	66,383	October
November		2,020,505	978,746	33,318	56,780	491,048	679	300,966	9,454	November
December		2,260,109	1,172,831	36,809	57,743	521,122	1,174	316,280	1,623	December
Total		27,378,503	11,779,016	446,222	673,513	6,156,690	3,474	3,680,611	2,905,733	Total
Ratio		1.0000	0.4302	0.0163	0.0246	0.2249	0.0001	0.1344	0.1061	Ratio
Actual	D10S	0.3048	0.1095	0.0052	0.0067	0.0646	0.0000	0.0361	0.0671	Actual
Actual	D10NS	0.6952	0.3207	0.0110	0.0179	0.1603	0.0001	0.0983	0.0391	Actual
	Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)									Growth Related Mo
	2006 Billed MWh x 1000		4,865	3,802	3,802	3,802	3,802	2,438	1,650	2006
	2016 Billed MWh x 1000		5,383	4,389	4,389	4,389	4,389	2,768	1,654	2016
			10.65%	15.44%	15.44%	15.44%	15.44%	13.54%	0.24%	
Monthly Coincident Demands Weighted by Marginal Demand Costs										Monthly Coincident
Power Supply Service - Generation										Power Supply Serv
January	0.00	0	0	0	0	0	0	0	0	January
February	0.00	0	0	0	0	0	0	0	0	February
March	0.00	0	0	0	0	0	0	0	0	March
April	0.00	0	0	0	0	0	0	0	0	April
May	14.33	3,183,709	1,146,429	76,820	125,482	1,156,775	0	612,713	14,843	May
June	14.62	3,680,334	1,404,274	108,047	132,931	1,325,183	0	633,785	24,754	June
July	15.34	4,239,650	1,740,952	124,240	149,816	1,429,303	0	716,769	22,681	July
August	7.49	1,976,463	822,170	50,179	70,623	668,289	0	328,312	9,589	August
September	8.99	2,140,883	822,575	54,609	91,787	749,892	0	379,800	10,248	September
October	0.00	0	0	0	0	0	0	0	0	October
November	0.00	0	0	0	0	0	0	0	0	November
December	8.23	2,200,059	1,027,737	46,771	73,372	662,163	1,492	352,332	32	December
Total		17,421,097	6,964,137	460,666	644,010	5,991,606	1,492	3,023,710	82,149	Total
Ratio		1.0000	0.3998	0.0264	0.0370	0.3439	0.0001	0.1736	0.0047	Ratio
Weighted	D10S	0.5681	0.2277	0.0162	0.0203	0.1965	0.0000	0.0964	0.0033	Weighted
Weighted	D10NS	0.4319	0.1720	0.0102	0.0167	0.1475	0.0001	0.0772	0.0014	Weighted

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
ED ALLOCATION FACTORS								
Demands @ Generation Level								
	2,068	4,458	706	2,065,531	37,132	23,494	84,280	144,906
	2,289	1,119	706	2,105,932	35,907	23,748	84,414	144,070
	2,068	0	706	1,875,819	34,351	22,892	83,985	141,229
	2,137	0	706	1,684,243	30,953	23,940	84,101	138,994
	2,068	0	706	2,111,599	22,462	23,554	90,029	136,044
	2,137	0	706	2,617,504	26,231	17,156	91,257	134,644
	2,068	0	706	2,742,985	23,752	23,504	93,569	140,825
	2,068	0	706	2,568,013	24,519	24,021	92,357	140,897
	2,137	0	704	2,290,292	23,253	22,556	90,754	136,564
	2,068	0	704	1,638,506	29,932	23,883	85,478	139,293
	2,134	2,413	726	1,876,265	34,844	23,161	86,235	144,240
	2,071	4,165	692	2,114,509	35,922	23,630	86,047	145,599
	25,311	12,154	8,475	25,691,198	359,260	275,539	1,052,507	1,687,305
	0.0009	0.0004	0.0003	0.9384	0.0131	0.0101	0.0384	0.0616
D10S	0.0002	0.0000	0.0001	0.2896	0.0027	0.0024	0.0101	0.0152
D10NS	0.0007	0.0004	0.0002	0.6488	0.0104	0.0077	0.0283	0.0464
nthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)								
Billed MWh x 1000	3,802	3,802	3,802		1,183	1,183	1,183	
Billed MWh x 1000	4,389	4,389	4,389		1,210	1,210	1,210	
	15.44%	15.44%	15.44%		2.28%	2.28%	2.28%	
:Demands Weighted by Marginal Demand Costs								
ice - Generation								
0.00	0	0	0	0	0	0	0	0
0.00	0	0	0	0	0	0	0	0
0.00	0	0	0	0	0	0	0	0
0.00	0	0	0	0	0	0	0	0
14.33	4,575	0	1,562	3,139,214	7,346	7,703	29,445	44,494
14.62	4,823	0	1,594	3,635,406	8,753	5,725	30,450	44,928
15.34	4,897	0	1,673	4,190,346	8,316	8,229	32,759	49,304
7.49	2,391	0	817	1,952,377	4,192	4,106	15,788	24,086
8.99	2,966	0	976	2,112,862	4,771	4,628	18,621	28,020
0.00	0	0	0	0	0	0	0	0
0.00	0	0	0	0	0	0	0	0
8.23	2,631	5,292	879	2,172,710	6,747	4,439	16,163	27,349
	22,283	5,292	7,501	17,202,916	40,125	34,830	143,226	218,181
	0.0013	0.0003	0.0004	0.9875	0.0023	0.0020	0.0082	0.0125
D10S	0.0007	0.0000	0.0002	0.5613	0.0012	0.0010	0.0045	0.0068
D10NS	0.0006	0.0003	0.0002	0.4262	0.0011	0.0010	0.0037	0.0057

IIPA
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS, BASED ON GROWTH
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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)	Month
Average	D10S	0.4364	0.1686	0.0107	0.0135	0.1305	0.0000	0.0663	0.0352	Average
Average	D10NS	0.5636	0.2464	0.0106	0.0173	0.1539	0.0001	0.0877	0.0202	Average
Total Ratio		1.0000	0.4150	0.0214	0.0308	0.2844	0.0001	0.1540	0.0554	Total Ratio

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
D10S	0.0005	0.0000	0.0002	0.4254	0.0020	0.0017	0.0073	0.0110
D10NS	0.0006	0.0004	0.0002	0.5375	0.0057	0.0043	0.0160	0.0261
	0.0011	0.0004	0.0004	0.9629	0.0077	0.0060	0.0233	0.0371

IIPA

DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS, BASED ON GROWTH

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

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)	Month
CAPACITY RELATED ALLOCATION FACTORS										CAPACITY RELAT
Monthly Coincident Demands @ Generation Level										Monthly Coincident
January		2,210,437	1,193,549	36,884	49,136	490,137	1,298	286,265	1,031	January
February		2,250,001	1,201,564	38,337	50,741	512,824	323	296,694	1,334	February
March		2,017,048	1,027,500	32,203	49,326	475,629	0	281,005	7,382	March
April		1,823,237	807,559	26,757	48,623	431,261	0	282,639	84,561	April
May		2,247,643	751,370	34,722	56,717	522,850	0	315,886	427,281	May
June		2,752,148	902,106	47,867	58,891	587,087	0	320,269	698,440	June
July		2,863,810	1,065,895	52,458	63,257	603,494	0	345,202	609,905	July
August		2,708,910	1,030,939	43,392	61,072	577,905	0	323,835	528,095	August
September		2,426,855	859,348	39,344	66,129	540,273	0	312,115	470,243	September
October		1,777,799	787,609	24,130	55,098	403,060	0	299,455	66,383	October
November		2,020,505	978,746	33,318	56,780	491,048	679	300,966	9,454	November
December		2,260,109	1,172,831	36,809	57,743	521,122	1,174	316,280	1,623	December
Total		27,378,503	11,779,016	446,222	673,513	6,156,690	3,474	3,680,611	2,905,733	Total
Actual	D13	1.0000	0.4302	0.0163	0.0246	0.2249	0.0001	0.1344	0.1061	Actual
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-38)										Growth Related Mo
2006 Billed MWh x 1000			4,865	3,802	3,802	3,802	3,802	2,438	1,650	2006
2016 Billed MWh x 1000			5,811	4,944	4,944	4,944	4,944	3,102	1,667	2016
			19.45%	30.04%	30.04%	30.04%	30.04%	27.24%	1.03%	
Monthly Coincident Demands Weighted by Marginal Transmission Costs										Monthly Coincident
Transmission Service										Transmission Serv
January	3.08	1,537,784	714,824	34,123	45,457	453,443	1,201	240,134	33	January
February	2.30	1,173,248	537,382	26,485	35,054	354,283	223	185,853	32	February
March	3.32	1,520,045	663,328	32,114	49,189	474,308	0	254,089	253	March
April	2.07	829,976	325,052	16,636	30,232	268,142	0	159,345	1,803	April
May	24.25	10,540,289	3,543,023	252,910	413,120	3,808,401	0	2,086,301	106,755	May
June	24.80	12,195,028	4,350,284	356,571	438,690	4,373,288	0	2,163,219	178,462	June
July	26.81	14,414,122	5,556,733	422,437	509,398	4,859,860	0	2,520,604	168,471	July
August	14.09	7,229,885	2,824,570	183,644	258,467	2,445,802	0	1,242,709	76,663	August
September	16.68	7,749,204	2,787,233	197,119	331,317	2,706,844	0	1,417,898	80,813	September
October	2.44	961,749	373,688	17,665	40,381	295,402	0	199,001	1,669	October
November	2.72	1,257,360	517,663	27,221	46,390	401,187	555	222,957	265	November
December	13.45	6,929,963	3,067,368	148,706	233,280	2,105,308	4,743	1,158,587	225	December
Total		66,338,518	25,261,146	1,715,650	2,430,975	22,546,269	6,722	11,850,696	615,444	Total
Weighted	D13	1.0000	0.3808	0.0259	0.0366	0.3399	0.0001	0.1786	0.0093	Weighted
Average	D13	1.0000	0.4055	0.0211	0.0306	0.2824	0.0001	0.1565	0.0577	Average

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
ED ALLOCATION FACTORS								
Demands @ Generation Level								
0.00	2,068	4,458	706	2,065,531	37,132	23,494	84,280	144,906
0.00	2,289	1,119	706	2,105,932	35,907	23,748	84,414	144,070
0.00	2,068	0	706	1,875,819	34,351	22,892	83,985	141,229
0.00	2,137	0	706	1,684,243	30,953	23,940	84,101	138,994
0.00	2,068	0	706	2,111,599	22,462	23,554	90,029	136,044
0.00	2,137	0	706	2,617,504	26,231	17,156	91,257	134,644
0.00	2,068	0	706	2,742,985	23,752	23,504	93,569	140,825
0.00	2,068	0	706	2,568,013	24,519	24,021	92,357	140,897
0.00	2,137	0	704	2,290,292	23,253	22,556	90,754	136,564
0.00	2,068	0	704	1,638,506	29,932	23,883	85,478	139,293
0.00	2,134	2,413	726	1,876,265	34,844	23,161	86,235	144,240
0.00	2,071	4,165	692	2,114,509	35,922	23,630	86,047	145,599
	25,311	12,154	8,475	25,691,198	359,260	275,539	1,052,507	1,687,305
D13	0.0009	0.0004	0.0003	0.9384	0.0131	0.0101	0.0384	0.0616
nthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)								
Billed MWh x 1000	3,802	3,802	3,802		1,183	1,183	1,183	
Billed MWh x 1000	4,944	4,944	4,944		1,294	1,294	1,294	
	30.04%	30.04%	30.04%		9.38%	9.38%	9.38%	
Demands Weighted by Marginal Transmission Costs								
ice								
3.08	1,913	4,124	653	1,495,907	10,731	6,790	24,357	41,877
2.30	1,582	773	488	1,142,157	7,749	5,125	18,217	31,091
3.32	2,062	0	704	1,476,050	10,701	7,131	26,163	43,995
2.07	1,329	0	439	802,980	6,012	4,650	16,335	26,996
24.25	15,062	0	5,144	10,230,740	51,108	53,593	204,848	309,549
24.80	15,917	0	5,261	11,881,716	61,040	39,922	212,351	313,312
26.81	16,652	0	5,687	14,059,868	59,751	59,125	235,378	354,254
14.09	8,751	0	2,989	7,043,611	32,416	31,758	122,101	186,274
16.68	10,705	0	3,525	7,535,472	36,393	35,302	142,037	213,732
2.44	1,515	0	516	929,859	6,853	5,468	19,570	31,890
2.72	1,743	1,971	593	1,220,548	8,893	5,911	22,009	36,812
13.45	8,365	16,826	2,795	6,746,216	45,334	29,821	108,592	183,747
	85,596	23,694	28,794	64,565,124	336,979	284,595	1,151,956	1,773,530
D13	0.0013	0.0004	0.0004	0.9733	0.0051	0.0043	0.0174	0.0267
D13	0.0011	0.0004	0.0004	0.9558	0.0091	0.0072	0.0279	0.0442

IIPA

DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS, BASED ON GROWTH

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

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)	Month
ENERGY RELATED ALLOCATION FACTORS										ENERGY RELATE
Monthly Energy Requirements @ Generation Level										Monthly Energy Re
January		1,247,214	598,762	23,513	29,634	295,314	545	193,284	753	January
February		1,121,172	527,975	20,869	27,784	268,854	542	178,808	880	February
March		1,077,183	459,945	19,556	29,978	275,122	547	183,814	5,390	March
April		1,038,774	390,531	16,686	29,144	263,791	544	179,296	59,753	April
May		1,159,421	358,799	15,786	32,037	271,100	548	186,039	193,624	May
June		1,357,569	364,300	17,870	31,635	282,711	544	192,892	376,089	June
July		1,624,165	493,954	22,092	35,201	320,285	546	204,499	444,234	July
August		1,511,625	464,457	20,596	35,186	324,288	544	203,336	360,944	August
September		1,182,565	350,944	16,220	36,136	279,878	543	193,456	209,080	September
October		1,065,848	386,664	16,335	33,941	278,412	546	201,058	48,471	October
November		1,105,792	485,864	17,909	32,275	270,156	547	191,964	8,681	November
December		1,293,607	629,321	23,588	33,631	299,819	550	199,061	1,185	December
Total		14,784,934	5,511,515	231,020	386,583	3,429,730	6,546	2,307,305	1,707,083	Total
Ratio		1.0000	0.3728	0.0156	0.0261	0.2320	0.0004	0.1561	0.1155	Ratio
Actual	E10S	0.3039	0.0895	0.0041	0.0069	0.0627	0.0001	0.0406	0.0799	Actual
Actual	E10NS	0.6961	0.2833	0.0115	0.0192	0.1693	0.0003	0.1154	0.0356	Actual
Growth Related Monthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)										Growth Related Mo
2006 Billed MWh x 1000			4,865	3,802	3,802	3,802	3,802	2,438	1,650	2006
2016 Billed MWh x 1000			5,811	4,944	4,944	4,944	4,944	3,102	1,667	2016
			19.45%	30.04%	30.04%	30.04%	30.04%	27.24%	1.03%	
Monthly Energy Requirements Weighted by Marginal Energy Costs										Monthly Energy Re
Power Supply Service - Generation										Power Supply Serv
January	64.34	18,311,320	7,491,070	454,406	572,699	5,707,153	10,527	3,386,969	499	January
February	64.78	16,626,837	6,650,624	406,074	540,613	5,231,330	10,553	3,154,727	587	February
March	64.97	16,092,367	5,810,684	381,625	585,026	5,368,979	10,679	3,252,559	3,608	March
April	55.33	12,651,156	4,201,691	277,309	484,363	4,384,034	9,040	2,701,871	34,063	April
May	54.86	12,547,691	3,827,499	260,122	527,916	4,467,233	9,036	2,779,670	109,441	May
June	58.68	13,881,412	4,156,782	314,974	557,592	4,982,962	9,584	3,079,559	227,377	June
July	127.75	35,822,171	12,270,319	847,724	1,350,722	12,289,987	20,944	7,115,200	584,706	July
August	111.10	30,457,609	10,033,858	687,315	1,174,182	10,821,797	18,145	6,152,662	413,161	August
September	77.66	18,086,272	5,299,598	376,349	842,941	6,528,597	12,675	4,091,795	167,292	September
October	71.37	17,098,473	5,366,089	350,180	727,606	5,968,397	11,699	3,908,147	35,642	October
November	78.92	20,002,432	7,456,071	424,533	765,082	6,404,059	12,971	4,126,110	5,432	November
December	80.24	23,655,783	9,819,095	568,510	810,558	7,226,097	13,255	4,350,216	980	December
Total		235,233,524	82,383,380	5,351,121	8,939,301	79,380,624	149,107	48,099,484	1,582,787	Total
Ratio		1.0000	0.3502	0.0227	0.0380	0.3375	0.0006	0.2045	0.0067	Ratio
Weighted	E10S	0.3408	0.1125	0.0079	0.0131	0.1194	0.0002	0.0895	0.0052	Weighted
Weighted	E10NS	0.6592	0.2377	0.0149	0.0249	0.2180	0.0004	0.1350	0.0015	Weighted

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
D ALLOCATION FACTORS								
quirements @ Generation Level								
	1,510	1,871	506	1,145,692	22,758	17,313	61,451	101,522
	1,510	1,878	506	1,029,606	20,282	15,792	55,492	91,566
	1,510	1,885	506	978,253	19,967	17,461	61,502	98,930
	1,510	1,892	506	943,652	18,302	17,071	59,749	95,122
	1,510	1,900	506	1,061,847	17,525	17,567	62,480	97,573
	1,510	1,907	506	1,269,765	16,569	10,258	60,977	87,804
	1,510	1,914	506	1,524,741	17,281	17,470	64,672	99,424
	1,510	1,922	506	1,413,289	16,652	17,310	64,374	98,335
	1,510	1,929	504	1,090,200	14,955	16,532	60,878	92,365
	1,510	1,936	504	969,378	16,944	16,970	62,557	96,471
	1,508	1,944	520	1,009,367	19,299	16,671	60,455	96,425
	1,512	1,951	496	1,191,113	22,507	17,327	62,660	102,494
	18,118	22,929	6,071	13,626,903	223,043	197,742	737,247	1,158,032
	0.0012	0.0016	0.0004	0.9217	0.0151	0.0134	0.0499	0.0783
E10S	0.0003	0.0004	0.0001	0.2846	0.0034	0.0030	0.0129	0.0193
E10NS	0.0009	0.0012	0.0003	0.6371	0.0117	0.0103	0.0370	0.0590
nthly Coincident Demands between 2006 and 2016 (IPCo's 2006 IRP Sales and Load Forecast pages 26-36)								
Billed MWh x 1000	3,802	3,802	3,802		1,183	1,183	1,183	
Billed MWh x 1000	4,944	4,944	4,944		1,294	1,294	1,294	
	30.04%	30.04%	30.04%		9.38%	9.38%	9.38%	
quirements Weighted by Marginal Energy Costs								
vice - Generation								
64.34	29,179	36,153	9,778	17,698,434	137,391	104,518	370,977	612,886
64.78	29,378	36,546	9,845	16,070,277	123,278	95,989	337,293	556,560
64.97	29,465	36,784	9,874	15,489,282	121,723	106,443	374,920	603,086
55.33	25,093	31,450	8,409	12,157,322	95,016	88,624	310,193	493,833
54.86	24,880	31,302	8,337	12,045,436	90,212	90,427	321,617	502,256
58.68	26,612	33,613	8,918	13,397,973	91,226	56,481	335,733	483,439
127.75	57,936	73,455	19,415	34,630,407	207,148	209,410	775,206	1,191,764
111.10	50,385	64,130	16,884	29,432,519	173,589	180,443	671,058	1,025,090
77.66	35,220	45,001	11,757	17,413,225	108,975	120,465	443,607	673,047
71.37	32,367	41,511	10,808	16,452,448	113,470	113,640	418,916	646,025
78.92	35,742	46,079	12,325	19,288,404	142,909	123,446	447,673	714,028
80.24	36,439	47,024	11,947	22,884,119	169,449	130,455	471,759	771,663
	412,696	523,049	138,296	226,959,847	1,574,386	1,420,341	5,278,951	8,273,678
	0.0018	0.0022	0.0006	0.9648	0.0067	0.0060	0.0224	0.0352
E10S	0.0006	0.0007	0.0002	0.3293	0.0020	0.0019	0.0076	0.0115
E10NS	0.0012	0.0015	0.0004	0.6355	0.0047	0.0041	0.0149	0.0237

IIPA

DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS, BASED ON GROWTH

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

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)	Month
Average	E10S	0.3223	0.1010	0.0060	0.0100	0.0911	0.0002	0.0551	0.0426	Average
Average	E10NS	0.6777	0.2605	0.0132	0.0221	0.1936	0.0004	0.1252	0.0185	Average
Total Ratio		1.0000	0.3615	0.0192	0.0321	0.2847	0.0005	0.1803	0.0611	Total Ratio

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2007

Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
E10S	0.0004	0.0006	0.0001	0.3069	0.0027	0.0025	0.0102	0.0154
E10NS	0.0010	0.0013	0.0004	0.6363	0.0082	0.0072	0.0259	0.0414
	0.0015	0.0019	0.0005	0.9433	0.0109	0.0097	0.0362	0.0567

Exhibit No. 302
Case No. PAC-E-07-05
Anthony J. Yankel
"Growth Weighted Class Cost of Service Study Twelve Months Ending December 31, 2007"
1 page

GROWTH WEIGHTED
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2007

**** REVENUE REQUIREMENT SUMMARY ****

	(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	1,882,670,920	825,105,391	49,323,245	50,169,013	460,244,673	993,314	243,899,632	180,063,478	2,729,290	3,153,598	692,843	12,102,092	13,281,078	40,913,073
REVENUES FROM RATES														
RETAIL	617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL SALES REVENUES	617,820,268	294,087,610	15,381,328	12,772,697	126,221,210	931,147	65,869,474	70,750,659	880,610	2,056,146	188,543	5,384,849	4,657,881	18,638,114
TOTAL OTHER OPERATING REVENUES	178,391,078	66,509,749	3,499,898	6,494,899	47,307,133	200,823	33,214,542	10,642,925	235,113	489,765	83,777	1,770,011	2,093,530	5,848,912
TOTAL REVENUES	796,211,346	360,597,359	18,881,226	19,267,596	173,528,343	1,131,970	99,084,016	81,393,584	1,115,723	2,545,911	272,320	7,154,860	6,751,411	24,487,026
OPERATING EXPENSES														
WITHOUT INC TAX	629,346,490	268,546,136	16,738,444	17,676,858	156,287,665	957,688	91,305,001	46,978,923	926,061	2,376,933	259,508	5,047,394	4,695,909	17,549,970
OPERATING INCOME														
BEFORE INCOME TAXES	166,864,856	92,051,222	2,142,782	1,590,740	17,240,678	174,282	7,779,015	34,414,661	189,662	168,977	12,812	2,107,465	2,055,503	6,937,057
TOTAL FEDERAL INCOME TAX	46,753,611	20,490,387	1,224,877	1,245,880	11,429,560	24,688	6,056,926	4,471,635	67,778	78,315	17,208	300,539	329,818	1,016,021
TOTAL STATE INCOME TAX	2,849,268	1,248,729	74,647	75,927	696,543	1,503	369,122	272,511	4,131	4,773	1,049	18,315	20,100	61,919
TOTAL OPERATING EXPENSES	678,949,369	290,285,253	18,037,967	18,998,663	168,413,768	983,859	97,731,050	51,723,070	997,970	2,460,022	277,763	5,366,249	5,045,826	18,627,910
TOTAL OPERATING INCOME	117,261,977	70,312,106	843,258	268,933	5,114,575	148,111	1,352,966	29,670,514	117,753	85,889	-5,442	1,788,610	1,705,585	5,859,117
ADD: IERCO OPERATING INCOME	4,969,962	1,796,641	95,423	159,536	1,414,948	2,982	896,084	303,665	6,858	9,443	2,485	54,173	48,209	179,416
CONSOLIDATED OPER INCOME	122,231,838	72,108,747	938,681	428,469	6,529,524	151,093	2,249,051	29,974,179	124,711	95,332	-2,957	1,842,783	1,753,794	6,038,532
RATES OF RETURN	6.49	8.739	1.903	0.854	1.419	15.211	0.922	16.646	4.569	3.023	-0.427	15.227	13.205	14.759
RATES OF RETURN - INDEX	1.000	1.346	0.293	0.132	0.219	2.343	0.142	2.564	0.704	0.466	-0.066	2.345	2.034	2.273
REQUIRED REVENUE	681,765,526	291,671,449	20,773,462	19,121,491	180,197,072	822,684	96,461,928	46,844,872	1,059,495	2,342,917	290,793	4,060,210	3,645,094	14,474,061
REVENUE DEFICIENCY	83,945,258	-2,416,161	5,392,134	6,348,794	53,975,862	-108,463	30,592,454	-23,905,767	178,885	286,771	102,250	-1,324,639	-1,012,787	-4,164,053
PERCENT CHANGE REQUIRED	10.35%	-0.8%	35.1%	49.7%	42.8%	-11.6%	46.4%	-33.8%	20.3%	13.9%	54.2%	-24.6%	-21.7%	-22.3%

Exhibit 302

Exhibit No. 303
Case No. PAC-E-07-05
Anthony J. Yankel
"Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources Final Report-Volume I"
31 pages

Final Report – Volume I

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources

Prepared for PacifiCorp

July 11, 2007

In collaboration with Summit Blue Consulting and Nexant, Inc.

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Executive Summary

Overview

For nearly 25 years, PacifiCorp has been actively engaged in the design and delivery of demand-side management (DSM) products and services. Beginning with its management and sponsorship of the Hood River Conservation Project in the early 1980s, PacifiCorp has continued to be an innovator in energy efficiency and has conceived and implemented programs such as Energy FinAnswer, which, in its class, is considered one of the best programs in North America. Over the fast 15 years, PacifiCorp has invested approximately $345 million on DSM programs, offsetting nearly 2,700 GWh of energy – the equivalent of nearly 515 MW of capacity annually, assuming a 60% load factor on average.[1] Currently, PacifiCorp operates successful capacity-focused programs for irrigation load curtailment, demand buyback, and air conditioning direct load contsol, which together helped reduce PacifiCorp's peak loads by 149 MW in 2006. PacifiCorp also has an additional 260 MW available for control under interruptible agreements with a select group of its largest commercial and industrial customers.

Beginning in the early 1990s, PacifiCorp developed biennial integrated resource plans (IRPs) to identify the optimal, least-cost mix of supply and demand-side options to meet its projected long-run resource requirements. This report summarizes the results of an independent study to conduct a comprehensive, multi-sector assessment of the long-run potential for DSM resources in PacifiCorp's Pacific Power (Oregon: Washington, and California) and Rocky Mountain Power (Idaho, Wyoming, and Utah) service territories to support the PacifiCorp's integrated resource planning process and help further PacifiCorp's active pursuit of DSM resources.

This study's principal goal is to develop reliable estimates of the magnitude, timing, and costs of alternative DSM resources, comprised of capacity-focused program options (defined throughout this report as Class 1 and Class 3 DSM resources), energy-efficiency products and services (defined as Class 2 DSM resources), and other "supplemental" resources such as solar, combined heat and power, and dispatchable standby generation. The analysis of resource potential in this study are augmented by an examination of the benefits of consumer awareness and education initiatives (Class 4 DSM resources) and an analysis of how future structural changes, such as technological innovation, macroeconomic conditions, and public policy, might affect the findings and conclusions of this study.

The main emphasis of this study has been on resources with sufficient reliability characteristics, which are expected to be technically feasible (technical potential), cost-effective (economic potential), and realistically achievable (achievable potential) during the 20-year planning horizon. For Class2 DSM (energy-efficiency) resources, the methods used to evaluate the

---

1 Expenditures and savings include PacifiCorp's contributions to the Energy Trust of Oregon and the associated energy savings generated by those funds. All savings and capacity information calculated at generator.

2 Since the Energy Trust of Oregon is responsible for the planning and delivery of Class 2 DSM resources in Oregon, potential for these resources are exclusive of Oregon.

Figure 6. Class 1 DSM. Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2027)

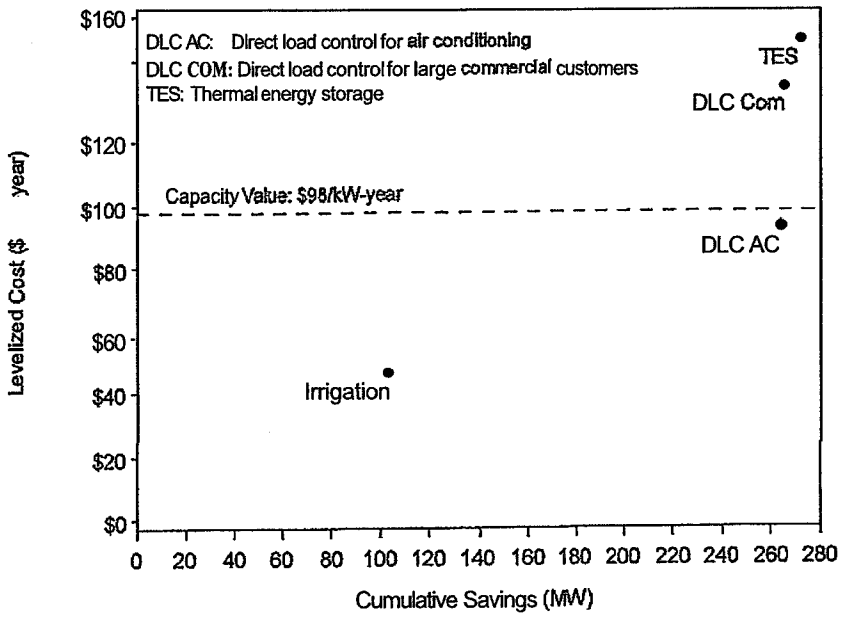
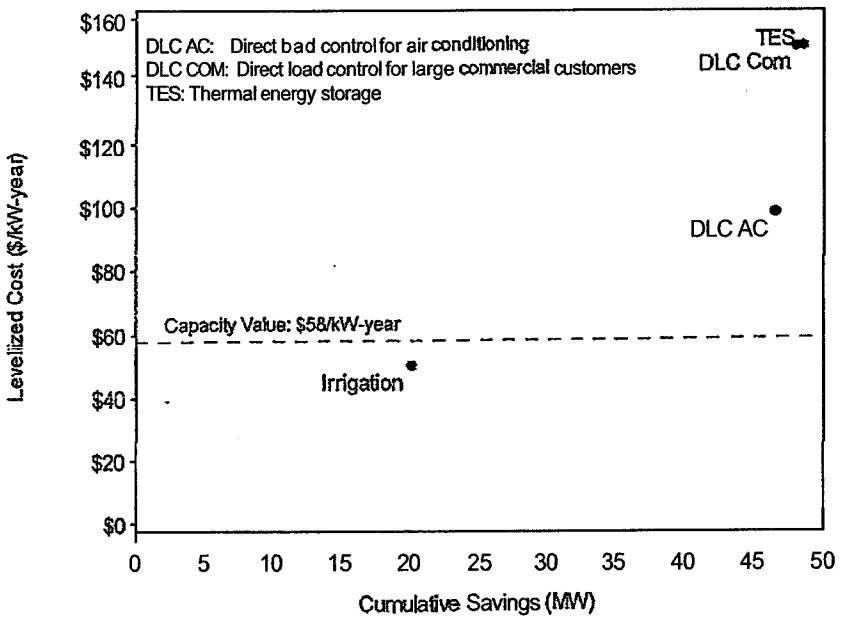


Figure 7. Class 1 DSM: Pacific Power Territory Supply Curve (Cumulative MW in 2027)



Irrigation

A program targeting irrigation is an ideal option to reduce summer peak due to the coincidence of irrigation pumping with mid-afternoon summer peaks. PacifiCorp's current irrigation load control program in Idaho is a scheduled control program; customers subscribe in advance for specific days and number of hours when their irrigation systems will be turned off. Load management is executed automatically based on a pre-determined schedule set through a timer device. Although a total of 100 MW of irrigation loads are contracted for management under this control program, less than half are available at any time due to the alternating schedules of program participants. In the Northwest, the Bonneville Power Administration (BPA) has run a pilot irrigation program (on a dispatched rather than scheduled basis), and Idaho Power has implemented a program similar to PacifiCorp's scheduled control program. In 2007, PacifiCorp began piloting a limited-scope 45 MW dispatchable program in addition to its scheduled control option. Presuming it will be successful, this analysis assumes that, in the future, half of the participants will sign up for the dispatchable control option and half will sign up for the scheduled control option.

Technically, it is assumed all irrigation loads are eligible for this program, excepting half of the Oregon load (which is horizontal pumping and not suitable for this offering). This results in a technical potential of 308 MW (Rocky Mountain Power) and 108 MW (Pacific Power).

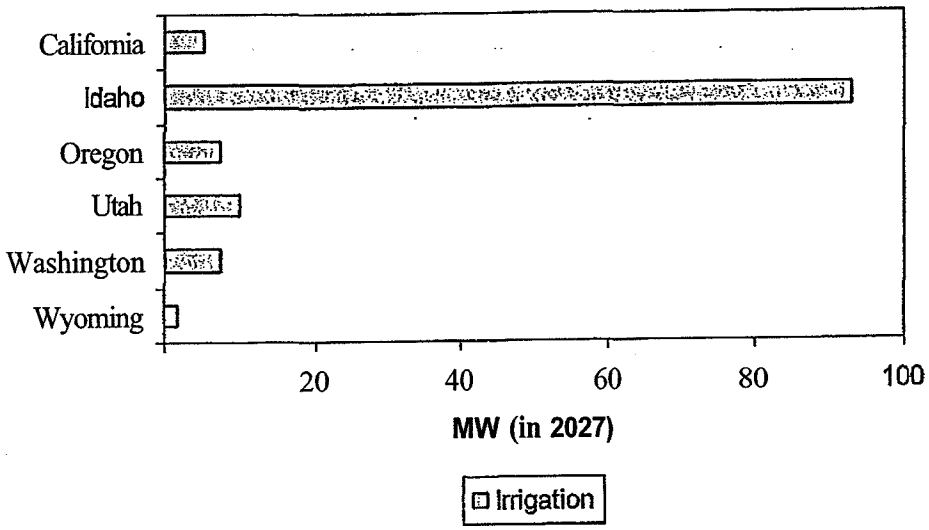
In terms of program participation, both PacifiCorp's and Idaho Power's scheduled control option programs have had solid participation rates: 35% and 25% of eligible load, respectively. This analysis assumes PacifiCorp *can* increase the participation rate in Idaho to 50% and will reach 25% in other states, where pumps tend to be smaller and loads are distributed across more customers. Assuming one-half of participants are on a scheduled control program, during any one event, only 75% of the load will be available. These factors lead to a market potential estimate of 20 MW for Pacific Power (<1% of 2027 territory peak). For Rocky Mountain Power, 104 MW is available, which includes the 81 MW of expected 2007 achievements (78 MW in Idaho and 3 MW in Utah).

Due to load distribution the majority of this is expected to wine from Idaho (93 MW). The PacifiCorp forecasts of irrigation loads expect an overall reduction of approximately 10% over the next 20 years, which is accounted for in the estitnate of potential in 2027.

Table **17.** Irrigation: Technical and Market Potential (MW in **2027**)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	---	---	---	---	---	---
Commercial	---	---	---	---	---	---
Industrial	---	---	---	---	---	---
Irrigation	308.3	104.2	21.3%	107.9	20.2	8.1%
Total	308.3	104.2	1.3%	107.9	20.2	0.4%

Figure 14. Irrigation: Market Potential by State (MW in 2027)



Costs for the irrigation program include $400,000 for upfront program costs, $1,000 for installed technology with a life of seven years, $500 for marketing to new customers, and $10/kW for ongoing maintenance and communication systems based on Rocky Mountain Power's experience. Although PacifiCorp currently pays $11/kW-year for incentives (2006 program year), participation level assumptions are based on a higher incentive amount of $20/kW-year in recognition that greater penetration will require higher incentives and the emergence of the dispatchable control option is expected to increase the value of the control to PacifiCorp.

Table 18 displays the resulting levelized costs for the irrigation. With an expected cost of $47/kW-year and $50/kW-year (Rocky Mountain Power and Pacific Power territories, respectively), this program option passes all economic screens. The high achievable scenario assumes a 20% increase in participation and a 50% increase in incentives. With a high achievable cost of $67/kW-year and $70/kW-year (Rocky Mountain Power and Pacific Power, respectively), irrigation in the Rocky Mountain Power territory passes all economic scenarios.

Table 18. Irrigation: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	Base	High
Rocky Mountain Power					
Expected Achievable	104	$47	Pass	Pass	Pass
High Achievable	125	$67	Pass	Pass	Pass
Pacific Power					
Expected Achievable	20	$50	---	Pass	Pass
High Achievable	24	$70	---	---	Pass

Table 24 also shows the high achievable scenario, assuming all respondents indicating a "very positive" reaction to the program and one-half of those indicating "somewhat positive" can be convinced to participate, resulting in 29% of customers, or 38 MW for Rocky Mountain Power and 15 MW for the Pacific Power territory. Consistent with all other programs, the high achievable scenario is assumed to have a 50% increase in incentives; so costs rise to $24/kW-year, which again pass all economic screens.

Table 24. Demand Buyback: Levelized Costs and Scenarios

	MW Potential	Levelized Cost	Economic Screen		
			Low	**Base**	High
Rocky Mountain Power					
Expected Achievable	26	**$18**	Pass	Pass	Pass
High Achievable	38	$24	Pass	Pass	Pass
Pacific Power					
Expected Achievable	10	**$18**	Pass	Pass	Pass
High Achievable	15	$24	Pass	Pass	Pass

Residential Time of Use Rates

Information on TOU rates was obtained from tariffs from 60 U.S. utilities, promotional materials used by utilities offering new TOU (or TOU with CPP) programs during the past five years, and several interviews with utility staff members.[35] TOU rates have been offered by U.S. utilities since at least the 1970s, but the historic impacts have been quite low. In fact, PacifiCorp ran a TOU pilot in 2002 to 2004, which had extremely low program sign-up (940 residential customers at the end of 2004, with an average of 25% annual attrition), despite an intensive marketing effort.

The TOU rates developed in recent years typically differ from those of the past in several important ways. First, most new TOU rates contain three price tiers as opposed to the two-tier rates common in many long-standing TOU programs, including those offered by PacifiCorp. This allows utilities to set high prices during their highest peak periods and offer exceptionally low off-peak prices overnight when the wst is at its lowest and supply is plentiful. The majority of hours are assigned a "mid-peak" price that is typically a slightly discounted version of the standard rate. Another change is that the duration of the peak period is typically shorter than in the past. Finally, the price differentials between peak and off-peak prices tend to be greater than in the past to encourage load shifting away from the peak period. For long-standing TOU rates, this differential averaged about 7.6 cents/kWh, whereas newer programs tend to have a differential of greater than 10 cents/kWh. For comparison, PacifiCorp's existing TOU rates offer a price differential of roughly 4.5 cents/kWh to 7.5 cents/kWh, depending on the operating utility and the season.

[35] Includes: Gulf Power, Alabama Power, Ameren, Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric, and Teco Energy. Interviews with utility staff: Arizona Public Service, Salt River Project, and Florida Power and Light.

TOU rates are assumed to be available only to the residential customer segments, and the potential is based on the total load rather than individual end uses. The technically feasible portion of the load basis expected to be reduced during peak hours is 5% based on results from California[36] and Puget Sound Energy. The participation rate of the top ten highest-enrolled TOU programs in the country[37] is on average 16%, yet these programs do not represent the experience of all national programs, many of which have participation rates of <1%. If a robust marketing effort is made in conjunction with a TOU rate design that is more than double PacifiCorp's current TOU differential the expected participationrate is assumed to be 10%.

Table 25 shows there is 107 MW of technical potential and 11 MW of market potential in the Rocky Mountain Power territory. In the Pacific Power territory, there is 78 MW of technical potential and 8 MW of market, both representing less than 1% of 2027 territory peak.

Table 25. Time of Use Rates: Technical and Market Potential (MW in 2027)

Sector	Rocky Mountain Power			PacificPower		
	Technical Potential	Market Potential	Market as % of 2027 Peak	Technical Potential	Market Potential	Market as % of 2027 Peak
Residential	106.7	10.7	0.5%	77.6	7.8	0.4%
Commercial	---	---	---	---	---	---
Industrial	---	---	---	---	---	---
Irrigation	---	---	---	---	---	---
Total	**106.7**	**10.7**	0.1%	**77.6**	**7.8**	**0.2%**

Figure 18 shows Utah has the most potential, with 9 MW, followed by Oregon with nearly 6 MW.

Table 26 displays the per-unit costs, using the assumptions of $400,000 in prograni development (based on 2002 PGE and PacifiCorp TOU rate program development costs[38]), $125 in new participant costs ($100 per meter and $25 of marketing), with new participant costs reoccurring with annual attrition of 5% (based on electrical turnovers[39]) and a 20-year measure life on meters. Due to low per-customer impacts, the cost per kW-year is $166/kW-year for Rocky Mountain Power territory and $173/kW-year for Pacific Power territory, which pass the economic screens. This finding is consistent with the 2005 evaluation of PacifiCorp's TOU

36 Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot, Final Report," March 16,2005. See also, Piette, Mary Ann and David S. Watson "Participation through Automation: Fully Automated Critical Peak Pricing in Commercial Buildings," 2006, Lawrence Berkeley National Laboratory. Linkugel, Eric Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 2006.

37 FERC, 2006 and R. Gunn, "North American Demand Response Survey Results" (Association of Energy Services Professionals, Phoenix, AZ, February 2006).

38 Levelized per unit costs are driven primarily by hardware costs. Removal of upfront development reduces the results by $4/kW-year.

39 This is likely a conservative estimate - PacifiCorp 2004 pilot TOU program experienced up to 25% annual attrition.

Final Report – Volume II

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources: Appendices

Prepared for PacifiCorp

July 11, 2007

In Collaboration with Summit Blue Consulting and Nexant, Inc.

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Irrigation

Table B.9. Program Basics

Program Name	irrigation
Customer Sectors Eligible	Irrigation only
End Uses Eligible for Program	Irrigation Pumping
Customer Size Requirements, if any	All irrigation customers
Summer Load Basis	Top 40 Summer Hours
Winter Load Basis	No Winter

Table B.10. Inputs and Sources not Varying by State or Sector

Inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Based on changes in electrical service
Annual Administrative Costs (%)	15%	All resource classes assume admin adder of 15%
Technology Cost (per new participant)	$1,000	Technology costs assume $1000 per new participant for installation costs
Marketing Cost (per new partidpant)	$500	Both Idaho Power and PacifiCorp marketing costs are approximately $500 per new participant
Incentives (annual costs per participating kW)	$20	Idaho Power currently pays $16/kW/year; although Rocky Mountain Power pays $11/kW, high program participation raies and acceptance by customers can be attained only with higher Incentives, particularly in diverse geographic regions
Incentives (annual costs per partidpating kW)	$10	Ongoing Maintenance and Communications (per KW)
Overhead: First Costs (2007$)	$400,000	Standard Program Development Assumption, Including necessary Internal labor, research and IT/billing system changes
Technical Potential as % of Load Basis	100%	Assumes all loads can be controlled
Program Participation (%)	25%	Idaho Power and PacifiCorp have participation rates of 25% for the scheduled program. PacifiCorp has signed up an additional 45 MW for the DLC option, which totals 35% of the load basis. Assumes that more load Is available (50%)
Event Participation (%)	75%	Assumes that one-half of participants will be on scheduled program where participants choose 2 days of each week to schedule reductions during peak times (50% event participation for 50% of program Is an average of 75% event participation).
per Customer Impacts (kW)	Varies by Sector	Product of technical potential and average kW of customers greater than 250 kW (PC database of C&I customers)

Residential Time of Use Rates

Table B.20. Program Basics

Program Name	Time Of Use Rates
Customer Sectors Eligible	All Residential Market Segments
End Uses Eligible for Program	Total Load of All End Uses
Customer Size Requirements, if any	Residential
Summer Load Basis	Top 40 Summer Hours
Winter Load Basis	Top 40 Winter Hours

Table B.21. Inputs and Sources not Varying by State or Sector

inputs	Value	Sources or Assumptions
Annual Attrition (%)	5%	Consistent with PacifiCorp electric turnovers. Rate of 3.5% reported by Rosemary Morley of FPL.
Annual Administrative Costs (%)	15%	All resource classes assume admin adder of 15%
Technology Cost (per new participant)	$100	incremental cost of a TOU meter, APS and FERC 2006
Marketing Cost (per new participant)	$25	APS reported incremental costs of $20-$30 per new participant, including marketing costs and support.
Incentives (annual costs per participant)	$0	Bill savings may accrue for some customers, equating to lost revenues for the utility. This analysis assumes revenue neutrality for the utility.
Overhead: First Costs (2007$)	$400,000	Standard Program Development Assumption, including necessary internal labor, research and IT/billing system changes
Technical Potential as % of Load Basis	5%	California residential pricing programs results from CA SPP, fixed TOU show 5% average peak demand reduced (Charles River Associates, 2005). Results from Puget Sound Energy's cancelled TOU program are similar.
Program Participation (%)	10%	APS has the highest TOU enrollment of any utility in the country at nearly 400,000 participants or 45% of residential customers (Chuck Miessner, APS, 2007; FERC report of 2006). The participation rate of the top 10 highest-enrolled TOU programs in the country is on average 16% (excluding the mandatory rates by PS Oklahoma. Yet, these programs do not represent the experience of all national programs; many TOU programs around the country have participation rates of <1% (but many of these are legacy programs that are not being promoted). Even among the top 10 highest enrollment programs (according to FERC), half have single digit participation rates. if a reasonable effort is made, the reasonable low range might be 2%, which is the lowest participation rate among the top 10 programs, and an expected participation rate of 10%.
Event Participation (%)	100%	There are no "events" with TOU rates. Participation can be viewed as 100%.
per Customer impacts (kW)		Product of technical potential and average kW of customers based on load basis. Consistent with national studies.