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March 1, 2006

RECEIVED
MAR 2 PM 2:33
IDAHO PUBLIC UTILITIES COMMISSION

Jean Jewell, Secretary
Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Re: IPC-E-05-28

Dear Mrs. Jewell:

Enclosed herewith, please find the original and nine copies of Anthony J. Yankel's Direct Testimony on behalf of the Idaho Irrigation Pumper's Association, Inc.

Sincerely,

ERIC L. OLSEN

ELO:rr
Enclosures
cc: Service List

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2006 MAR -2 AM 9:33
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-05-28**

DIRECT TESTIMONY OF ANTHONY J. YANKEL

IDAHO IRRIGATION PUMPERS ASSOCIATION, INC.

MARCH 1, 2006

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 supports the Stipulation in this case. In support of the Stipulation, I
12 address the following areas that were reviewed by the Irrigators and that the Irrigators believe the
13 Stipulation adequately addresses the competing issues in this case.
14 • Power supply costs
15 • Disproportionate growth and allocation of growth between classes
16 • The Irrigation Load Curtailment Program

POWER SUPPLY COSTS

Q. WERE POWER SUPPLY COSTS AN IMPORTANT ISSUE IN THIS CASE?

A. Yes. The Irrigators put fort a great deal of effort addressing the calculation of power supply costs in this case. The concerns raised in the Company's filing centered around needing a higher rate of return, because (according to the Company) the actual results of the 90:10 sharing mechanism were not symmetrical. From the Irrigators perspective, the Power Supply Cost model appeared bias, resulting in an inappropriate test year cost and thus, a bias in the 90:10 sharing mechanism.

Q. DOES THE STIPULATION SPECIFICALLY ADDRESS POWER SUPPLY ISSUES THAT WOULD HAVE BEEN RAISED BY THE IRRIGATORS IF THIS WERE A CONTESTED CASE?

A. The issues that would have been raised by the Irrigators are not directly addressed in the Stipulation. However, Paragraphs 6a and 6d adequately serve as compromises for purposes of this case.

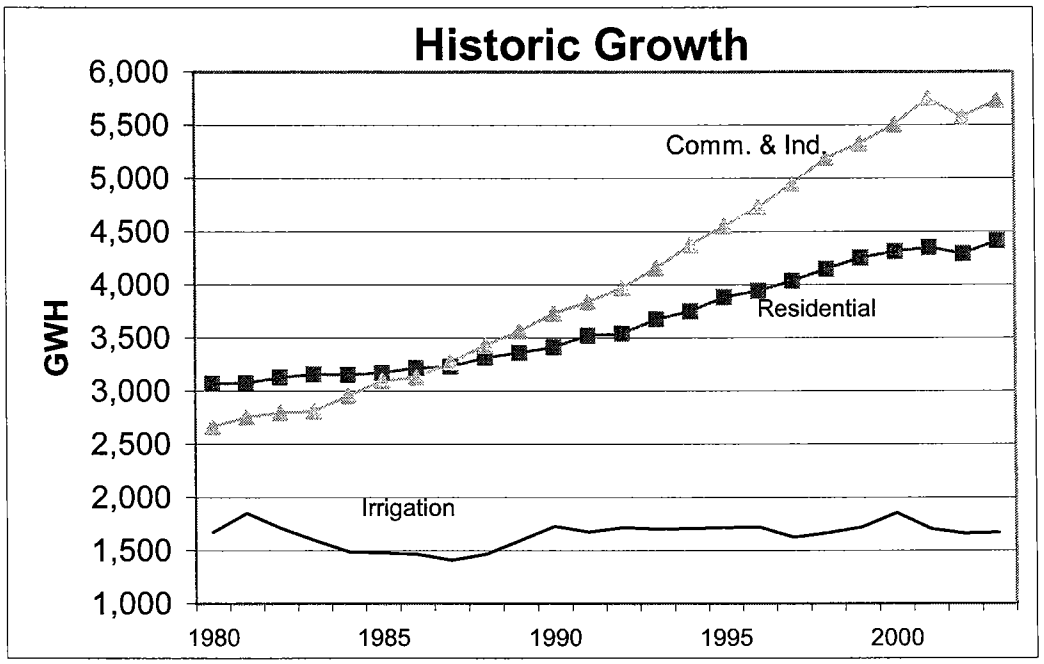
DISPROPORTIONATE GROWTH ON THE SYSTEM

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 FOR DECADES?

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

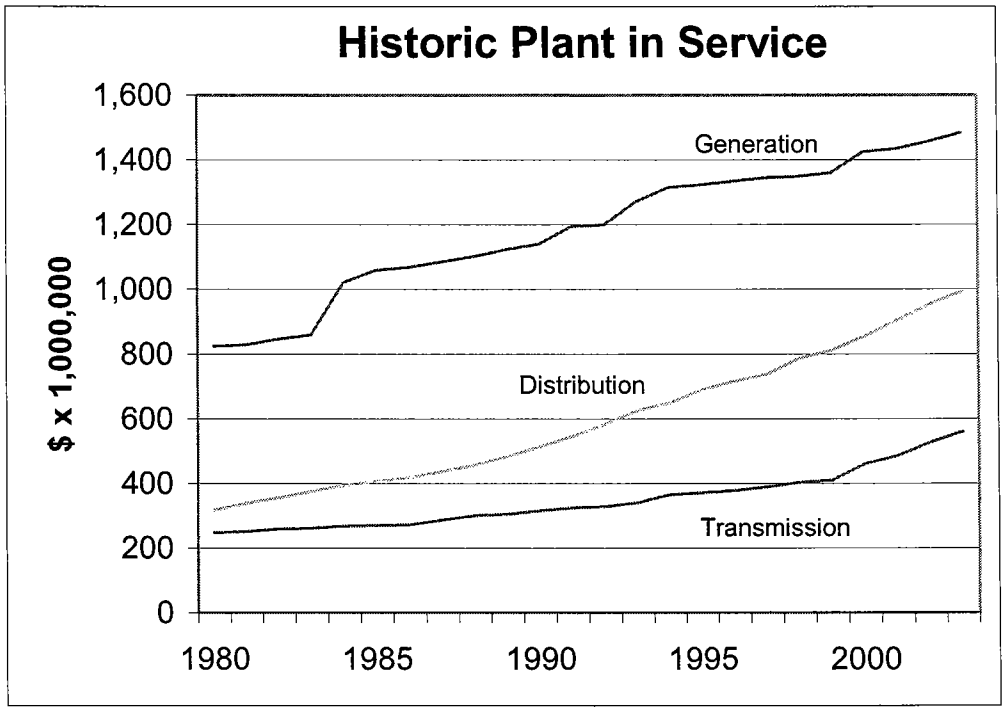


[1] Historic usage data taken from Appendix B of Idaho Power's 2004 IRP.

Over the last 25 years, the Irrigation load has been basically flat, Residential load has increased 45% and the combined Commercial/Industrial load has doubled. All customer classes, except the Irrigation class, have caused the phenomenal growth on the Idaho Power system.

Q. HAS THIS GROWTH IN LOAD BEEN ACCOMPANIED BY GROWTH IN UTILITY PLANT-IN-SERVICE?

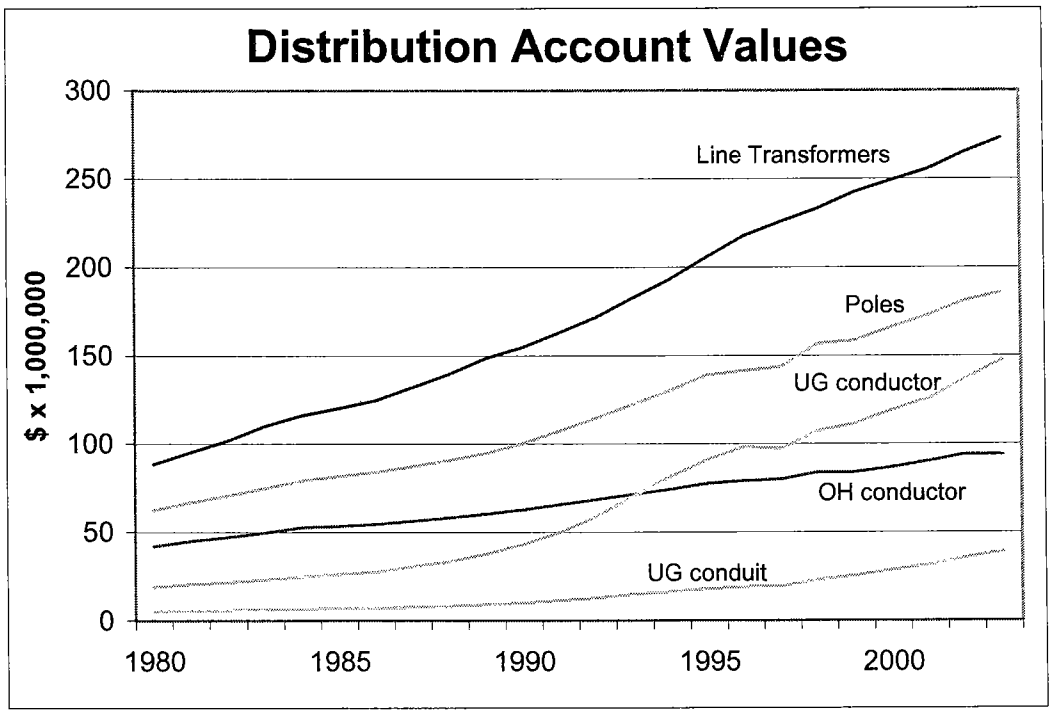
A. In order to keep up with this growth, there have been significant increases in Plant-In-Service at all functions as demonstrated by the following graph[2]:



In the last 25 years, Generation plant has increased $660 million or 80%, Transmission plant has increased $313 million (more than doubled its 1980 level), and Distribution plant has increased the most by adding an additional $685 million (over tripled its 1980 level).

[2] Data taken from FERC Form 1 for years 1980-2004.

Given the huge growth in Distribution Plant In Service, it is worthwhile to look at these accounts in more detail:



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

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

A. No. Inappropriately, the Company's cost of service study not only allocates this growth to the Irrigation class but, in some cases, it actually allocates a higher percentage of this growth than what is allocated to non-irrigation customers. This result is on its face counter-intuitive.

Q. WAS THE WORKSHOP THAT WAS INITIATED AS A RESULT OF THE LAST RATE CASE ABLE TO COME TO ANY CONCLUSIONS REGARDING THE TREATMENT OF 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 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, we were unable to devise a technical remedy to the allocation procedure that would also satisfy the courts. The parties were unable to devise and agree to a cost-of-service allocation methodology that would properly allocate the cost of growth, without making a distinction between new and old customers. Even a search of what others, around the country, were doing produced little in the way of an acceptable solution. Therefore, it was concluded that the only remedy is a policy solution. The parties were not willing to agree to the particulars of such a policy and recommend that the Commission formulate such a policy in the next rate proceeding. (Emphasis added)

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

A. No. As pointed out above, the workshop participants were not able to develop a consensus method for allocating the cost of growth in a manner that was acceptable to all parties. The problem with attempting to develop a consensus was recognized by various participants at the workshop. Although there was general consensus that there was something inherently very wrong with the present allocation scheme as related to its ability to allocate the cost of growth, no one felt that they could go back to their clients and admit that they agreed to a methodology that would cost their client more money—this decision was left to the Commission.

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

A. The Company's last rate case was only two years ago. Following the trend that has been in place for more than two decades, the non-Irrigation load has increased, while the Irrigation load has either stayed even or decreased. The following is a comparison of the coincident demand data utilized in both this case and the last case:

Sum of 12 CP's (MW)[3]	2003	2005	% Change
Irrigation	3,376,732	3,153,061	93.4%
Non-Irrigation	21,540,493	22,071,766	102.5%

[3] 2003 data comes from Case No. IPC-E-03-13, Company Exhibit 40, the unweighted data on page 1, while 2005 data comes from Case No. IPC-E-05-28, Company Exhibit 41, the unweighted data on page 1.

From the above, it can be seen that during the last two years the coincident demand (MW's) of the Irrigation load has decreased 6.6%, while the Non-Irrigation coincident demands have increased 2.5%. A similar pattern can be seen with respect to the annual system peak demand that occurs in July:

Annual System Peak	2003	2005	% Change
Irrigation	783,467	676,221	86.3%
Non-Irrigation	1,959,000	2,048,404	104.6%

As can be seem from above, the changes in load at the time of the single annual system peak are even more striking. During the last two years, the annual coincident demand of the Irrigation load has decreased 13.7%, while the Non-Irrigation annual coincident demands have increased 4.6%. A similar pattern can be seen with respect to the annual energy consumption:

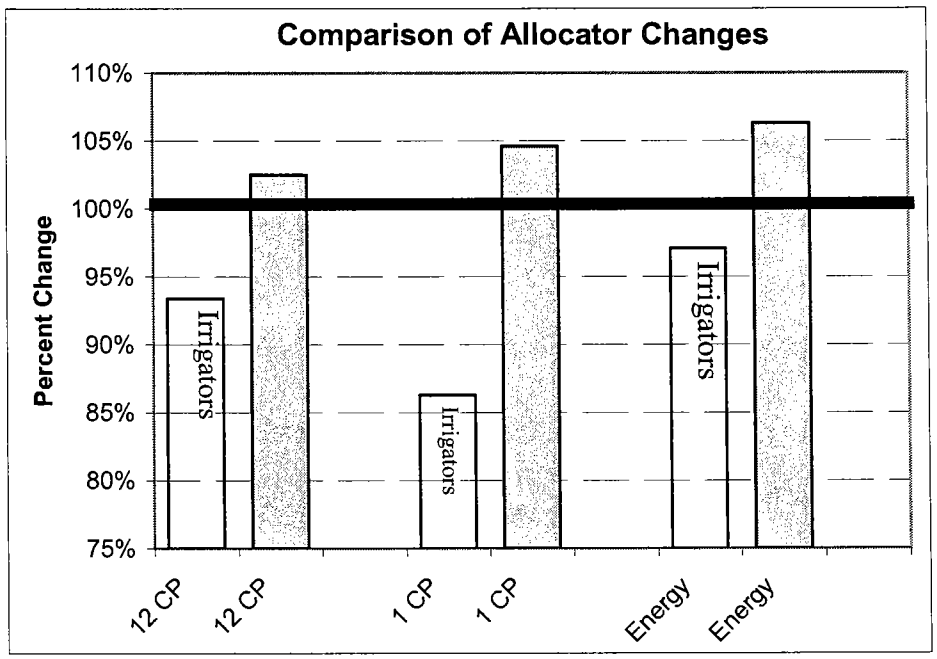
Annual Energy Usage	2003	2005	% Change
Irrigation	1,797,613	1,745,679	97.1%
Non-Irrigation	11,477,393	12,204,846	106.3%

As can be seem from above, the changes in annual energy usage follow the same pattern. Over the last two years the Irrigation usage has decreased 2.9% while Non-Irrigation usage has increased 6.3%.

Contrary to this outright reduction in demand and energy responsibility for the Irrigation customers over the last two years, the Company's cost of service study produced counter-intuitive results. A comparison of the allocated demand related production costs between this case and the case from just two years ago reveals the following:

Production costs[4] (x$1000)	2003	2005	% Change
Irrigation	$116,616	$124,965	107.2%
Non-Irrigation	$581,685	$589,525	101.3%

The following chart depicts the fact that the that these billing determinants have all decreased for the Irrigators since the last case, but the percentage increase in production related costs have gone up more for the Irrigators than the rest of the customers on the system—basically, the Irrigators are being allocated more while using less:



Thus, in spite of the fact that over the last two year the Irrigation demand has decreased (both on a 12-CP basis as well as a peak month basis), while the Non-Irrigation demand has increased, and overall energy use has followed the same pattern; the Company's cost of service study assigns an <u>increase</u> in demand related production cost to the Irrigators of 7% while the rest of the customers (that actually increased demand and energy consumption) only get an increase of 1%.

[4] 2003 data comes from Case No. IPC-E-03-13, Company Exhibit 39, page 3 lines 70 and 71, while 2005 data comes from Case No. IPC-E-05-28, Company Exhibit 37, page 3 lines 60 and 61.

This result is not only absurd, but it demonstrates the inability of the Company's cost of service model to address the imbalance of growth that has been taking place on the Idaho Power system for decades.

Q. DID THE WORKSHOP PARTICIPANTS RECOGNIZE OR ADDRESS THE ABSURDITY OF THIS RESULT IN THE COMPANY'S COST OF SERVICE STUDY?

A. No. It should be pointed out that the workshop participants did not have before them the information showing that since the last rate case the Irrigation load had decreased, while its allocated percentage increase in costs was larger than that of the system as a whole. Even without this information, the workshop participants recognized that there was a problem regarding the allocation of growth related costs that needed to be addressed.

Q. DOES THE COMPANY'S COST OF SERVICE STUDY ATTEMPT TO REFLECT BOTH ACTUAL AS WELL AS MARGINAL COSTS IN ITS ALLOCATION OF PRODUCTION AND TRANSMISSION RELATED COSTS?

A. Yes. It is the Company's position that the use of both actual and marginally weighted monthly peak demands and energy usage levels is appropriate for the allocation of Generation and Transmission related costs. Ms. Brilz testified:

> 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.[5]

1 I agree with the Company's approach to strike a balance between backward-looking costs
2 already incurred and forward-looking costs to be incurred in the future. Given the uneven
3 growth on the Idaho Power system, I recommend that the Commission adopt a similar position.
4 However, as has been demonstrated above, the Company's present cost of service study does not
5 accomplish this goal.

6 The balance between historic and forward looking costs that is struck in the Company's
7 study is based upon half of the allocation being based upon an unweighted 12-CP allocation that
8 is designed to reflect today's share of cost causation on the system[6]. It is the other half of the
9 allocation that purports to reflect forward-looking cost where the major problem occurs. The
10 Company's method inappropriately takes the same test-year 12-CP usage characteristics (present
11 day usage) and combines it with marginal weighting factors that reflect "forward-looking costs
12 to be incurred in the future" in order to meet growth. Thus, the Irrigators (as well as all classes)
13 get assigned costs, based upon weighting factors designed to reflect growth that is going to be
14 incurred by the System in the future, but not based upon the usage/growth that is going to create
15 those costs. Thus, unrealistic results occur where the Irrigation load is decreasing, but the cost of
16 the system growth is being assigned to it, not based upon future growth of the Irrigators over the
17 next five years, but based upon the historic usage of the Irrigators and all other classes.
18

19 Q. HOW COULD THE COMPANY'S ALLOCATION METHODOLOGY BE
20 BETTER ALIGNED TO REFLECT ITS STATED PURPOSE OF USING "BACKWARD-
21 LOOKING COSTS ALREADY INCURRED AND FORWARD-LOOKING COSTS TO BE
22 INCURRED IN THE FUTURE"?

---

[5] Brilz direct testimony at page 19.

A. The simplest way to correct the Company's existing study would be to continue to define "backward-looking costs" as test year costs and "forward-looking costs" as those anticipated in the Company's IRP for the next five years (the same five years as presently used in developing the Company's weighting factors). The "backward-looking costs" would simply be costs as they exist today and allocated on the basis of today's energy or 12-CP as is presently done in the Company's cost of service study. The "forward-looking costs" would be based upon the same weighting factors developed by the Company associated with the cost of growth anticipated over the next five years, but would be allocated on the basis of only the growth that is anticipated from each rate schedule over the next five years. The relative share of historic costs and anticipated costs related to growth would then be averaged using the Company's existing procedure in order to develop a composite allocation factor for use in spreading test year costs for allocation purposes. In this manner, present costs would be allocated on the basis of present usage and future costs would be allocated based upon those classes causing the additional growth.

Q. HOW COULD THE CHANGE THAT YOU PROPOSE BE IMPLEMENTED TO THE COMPANY'S COST OF SERVICE STUDY IN ORDER TO INSURE THAT THESE COUNTER-INTUITIVE RESULTS DO NOT OCCUR?

[6] 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.

A. One very simple change could be made. Instead of combining these growth related weighting factors with existing billing determinants, they could be combined with the same forecasted growth that served as a basis for these forecasted costs in the first place.

The Company's 2004 IRP that served as a basis for developing the weighted cost factors can also serve as the source of the data for the forecasted growth as well. In Exhibit AJY-1, I have simply modified the Company's allocation weighting procedure to apply the marginal cost weightings developed by the Company to only the growth that is expected over the next five years. For example, the Company's Exhibit 46 page 1 takes the January normalized demand for the Residential class and multiplies it by a weighting of 0.05 in order to develop a weighted demand of 55,264[7]. The original figure of 1,105,285 is a test year value and not reflective of the growth that will take place over the next five years. According to the Company's 2004 IRP[8], the average load for the Residential class will increase from 513 to 568 average megawatts or 10.7% between 2004 and 2009. The Company's billing unit of 1,105,285 needs to be modified in order to reflect the fact that only 10.7% of this figure will be associated with the cost of growth over the next five years.

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

A. Based upon the Company's 2004 IRP[9], the following growth percentages were calculated:

---

[7] 1,105,285 x 0.05 = 55,264
[8] Idaho Powers 2004 IRP—Sales and Load Forecast page 33.
[9] Idaho Powers 2004 IRP—Sales and Load Forecast pages 33-47

Residential	10.7%
Commercial (Sch. 7, 9, 40, 42)	18.9%
Industrial (Sch. 19)	16.7%
Irrigation	1.5%
Special Contracts	11.5%
System Load	12.8%

I utilized these percentages as the basis for calculating the amount of growth (beyond test year billing determinants) associated with the Generation and Transmission plant. I made no calculation to reflect the increase in Distribution plant that is almost as large as the growth in Generation and Transmission plant combined.

Q. WHAT IS THE IMPACT ON THE COMPANY'S COST OF SERVICE STUDY WHEN GROWTH RELATED WEIGHTING FACTORS ARE ONLY APPLIED TO THE GROWTH THAT IS ASSOCIATED WITH THOSE COSTS AND HOW DO THOSE RESULTS COMPARE WITH THE NORMALIZED STUDY IN THE COMPANY FILING?

A As can be seen from Exhibit AJY-2 and as summarized for the major rate schedules below, there is a major difference between the indexed rates of return that result from using properly aligned weighting factors with expected growth compared to the Company's Normalized study that does not link future marginal cost weighting factors with growth.

Study	Res.	Sch. 9 (s)	Sch. 19	Irr.
Growth Corrected	1.329	0.383	0.465	2.191
Company's Normalized	1.133	1.005	0.971	0.571

1 Although the difference between these two cost of service runs is quite large for some rate
2 schedules, it should come as little surprise. It has been well recognized by virtually all parties
3 that the Company's present allocation method does not properly address the cost of growth and
4 the fact that for over twenty years the Irrigators have been getting saddled (under that method)
5 with costs that they have not placed upon the system.

6 By way of contrast, the Growth Corrected study follows more intuitive logic. The growth
7 on the system over the last two-plus decades has not been even across all classes. Irrigation load
8 has been virtually flat, Residential load has increased rapidly, but not as rapidly as Commercial
9 and Industrial load. Given the growth in average system load[10] of 12.7% that is predicted over
10 the next five years in the 2004 IRP, any rate group that would be growing less than the average
11 should be getting a smaller share (compared to its size) of the marginal costs, while those
12 growing faster should get a higher percentage. The Irrigation growth is very low, Residential
13 and Special Contract growth is less than the average, with Commercial and Industrial load being
14 above average system growth. Given this picture of the expected growth, Irrigators should get
15 very little (if any) of the marginal cost of new plants, Residential and Special Contracts should
16 get less than the system average, and Commercial and Industrial should get a higher percentage
17 than system average. Given the fact that the Corrected Growth cost of service run recognizes the
18 link between growth and the growth related weighting factors, the resulting indexed rates of
19 return are quite logical:

20 • The Residential growth rate is somewhat less than the system average; therefore, the
21 indexed rate of return goes up a little when compared to the Normalized study.

[10] Idaho Powers 2004 IRP Sales and Forecast at page 47 shows sales in 2009 of 15,000 GWh compared to 13,283 GWh in 2004 for a difference of 12.7%.

- The Commercial growth rate is significantly above system average; therefore, the indexed rate of return for Schedule 9 significantly drops when compared to the Normalized study.
- 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 AJY-2 REFLECT THE GROWTH DIFFERENTIAL THAT IS ASSOCIATED WITH THE DISTRIBUTION SYSTEM?

A. No. Exhibit AJY-2 only reflects changes to the Company's cost of service study to reflect growth on the Generation and Transmission system. Over the last two-plus decades, the growth in Plant-in-Service associated with the Distribution system has been almost as great as the Generation and Transmission system combined. 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 20-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.

1 Q. DO YOU RECOMMEND THE USE OF THE RESULTS OF EXHIBIT AJY-2
2 FOR PURPOSES OF DECISIONS REGARDING RATE SPREAD IN THIS CASE?
3
4 A. If this case were contested, my recommendations would be to use the results of
5 Exhibit AJY-2 as the basis for the rate spread. The Irrigators have been targeted for
6 disproportionate rate increases for decades based upon studies that do not address the
7 disproportionate cost of growth on the system. The Commission should not view the
8 recommendation for an even spread of the increase in this case as something that is beneficial to
9 the Irrigators. Such a view could only be based upon cost of service results that do not account
10 for the disproportionate growth that has been taking place on the Idaho Power system. Because
11 the stipulated increase in this case is small and for a number of other reasons, the Irrigators are
12 willing to accept an even spread of the rate increase for purposes of this case only.

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 DSM 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 Schedule 23. However, the Irrigators recognize that it is too late this year to make changes to the program that could be put into effect for this year's irrigation season. With this in mind, the Irrigators have agreed to the provisions of paragraph 10 of the Stipulation which calls for the convening of a working group to review this program later this fall.

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2005

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

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	TOTAL	RESIDENTIAL (1)	GEN SRV (7)	GEN SRV PRIMARY (9-P)	GEN SRV SECONDARY (9-S)	AREA LIGHTING (15)	LG POWER PRIMARY (19-P)	IRRIGATION SECONDARY (24-S)
TOTAL RATE BASE	1,654,255,988	674,797,459	60,636,359	43,887,211	408,177,336	1,029,640	226,331,286	160,474,798
REVENUES FROM RATES								
RETAIL	562,123,417	258,380,596	20,731,009	11,536,794	109,545,928	938,956	61,563,466	69,540,884
TOTAL SALES REVENUES	562,123,417	258,380,596	20,731,009	11,536,794	109,545,928	938,956	61,563,466	69,540,884
TOTAL OTHER OPERATING REVENUES	108,799,813	37,934,956	3,184,662	3,667,333	27,266,879	128,546	21,746,846	7,085,950
TOTAL REVENUES	670,923,230	296,315,552	23,915,671	15,204,127	136,812,807	1,067,502	83,310,312	76,626,834
OPERATING EXPENSES								
WITHOUT INC TAX	515,726,215	210,255,915	19,541,761	14,021,932	123,759,062	536,470	74,485,493	42,382,016
OPERATING INCOME								
BEFORE INCOME TAXES	155,197,015	86,059,636	4,373,910	1,182,195	13,053,744	531,032	8,824,818	34,244,818
TOTAL FEDERAL INCOME TAX	44,012,228	24,405,600	1,240,394	335,258	3,701,903	150,595	2,502,625	9,711,467
TOTAL STATE INCOME TAX	4,722,601	2,618,770	133,097	35,974	397,222	16,159	268,537	1,042,060
TOTAL OPERATING EXPENSES	564,461,044	237,280,286	20,915,253	14,393,163	127,858,188	703,224	77,256,655	53,135,543
TOTAL OPERATING INCOME	106,462,185	59,035,266	3,000,418	810,963	8,954,619	364,278	6,053,657	23,491,291
ADD: IERCO OPERATING INCOME	6,061,133	1,988,658	176,985	190,320	1,684,389	3,637	1,105,551	429,128
CONSOLIDATED OPER INCOME	112,523,318	61,023,923	3,177,403	1,001,283	10,639,008	367,914	7,159,207	23,920,419
RATES OF RETURN	6.802	9.043	5.240	2.281	2.606	35.732	3.163	14.906
RATES OF RETURN - INDEX	1.000	1.329	0.770	0.335	0.383	5.253	0.465	2.191
AVERAGE MILLS/KWH	48.54	57.37	69.88	35.01	38.85	158.24	29.93	44.18
REVENUE REQUIREMENT CALCULATION								
RATE OF RETURN REQUIRED	8.420	8.420	8.420	8.420	8.420	8.420	8.420	8.420
REQUIRED REVENUE	606,071,606	251,474,381	23,897,077	15,960,375	148,509,806	477,195	81,099,796	52,450,224
REVENUE DEFICIENCY	43,948,189	-6,906,215	3,166,068	4,423,581	38,963,878	-461,761	19,536,330	-17,090,660
PERCENT CHANGE REQUIRED	7.82%	-2.67%	15.27%	38.34%	35.57%	-49.18%	31.73%	-24.58%
RETURN AT CLAIMED ROR	139,288,354	56,817,946	5,105,581	3,695,303	34,368,532	86,696	19,057,094	13,511,978
EARNINGS DEFICIENCY	26,765,036	-4,205,977	1,928,178	2,694,020	23,729,524	-281,219	11,897,887	-10,408,441

IDAHO POWER COMPANY
CLASS COST OF SERVICE STUDY
TWELVE MONTHS ENDING DECEMBER 31, 2005

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

		(I)	(J)	(K)	(L)	(M)	(N)
	TOTAL	UNMETERED GEN SERVICE (40)	MUNICIPAL ST LIGHT (41)	TRAFFIC CONTROL (42)	SC DOE/INL	SC JR SIMPLOT	SC MICRON
TOTAL RATE BASE	1,654,255,988	2,524,418	2,681,778	925,557	13,305,513	14,665,320	44,819,314
REVENUES FROM RATES							
RETAIL	562,123,417	873,387	1,892,969	261,633	5,000,777	4,499,930	17,357,088
TOTAL SALES REVENUES	562,123,417	873,387	1,892,969	261,633	5,000,777	4,499,930	17,357,088
TOTAL OTHER OPERATING REVENUES	108,799,813	148,892	168,043	75,361	1,302,484	1,729,068	4,360,794
TOTAL REVENUES	670,923,230	1,022,279	2,061,012	336,994	6,303,261	6,228,998	21,717,882
OPERATING EXPENSES							
WITHOUT INC TAX	515,726,215	794,937	1,869,127	313,436	5,069,759	4,902,803	17,793,504
OPERATING INCOME							
BEFORE INCOME TAXES	155,197,015	227,342	191,885	23,558	1,233,501	1,326,196	3,924,378
TOTAL FEDERAL INCOME TAX	44,012,228	64,472	54,417	6,681	349,808	376,095	1,112,912
TOTAL STATE INCOME TAX	4,722,601	6,918	5,839	717	37,535	40,356	119,418
TOTAL OPERATING EXPENSES	564,461,044	866,327	1,929,382	320,833	5,457,102	5,319,254	19,025,834
TOTAL OPERATING INCOME	106,462,185	155,952	131,629	16,160	846,158	909,745	2,692,049
ADD: IERCO OPERATING INCOME	6,061,133	9,092	10,910	4,849	86,674	80,613	290,328
CONSOLIDATED OPER INCOME	112,523,318	165,044	142,539	21,009	932,833	990,358	2,982,377
RATES OF RETURN	6.802	6.538	5.315	2.270	7.011	6.753	6.654
RATES OF RETURN - INDEX	1.000	0.961	0.781	0.334	1.031	0.993	0.978
AVERAGE MILLS/KWH	48.54	53.90	101.20	33.36	24.43	23.98	25.76
REVENUE REQUIREMENT CALCULATION							
RATE OF RETURN REQUIRED	8.420	8.420	8.420	8.420	8.420	8.420	8.420
REQUIRED REVENUE	606,071,606	951,401	2,029,692	355,100	5,308,638	4,901,337	18,656,582
REVENUE DEFICIENCY	43,948,189	78,014	136,723	93,467	307,861	401,407	1,299,494
PERCENT CHANGE REQUIRED	7.82%	8.93%	7.22%	35.72%	6.16%	8.92%	7.49%
RETURN AT CLAIMED ROR	139,288,354	212,556	225,806	77,932	1,120,324	1,234,820	3,773,786
EARNINGS DEFICIENCY	26,765,036	47,512	83,266	56,923	187,492	244,462	791,409

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005
Normalized Demands with Weights Only Applied to Future Growth

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,093,008	1,105,285	56,693	50,045	451,865	0	284,520	1,189
February		2,056,625	1,063,727	54,611	49,445	455,984	0	290,191	1,342
March		1,898,117	961,888	43,884	47,573	429,856	0	269,688	5,060
April		1,791,626	745,639	45,615	48,891	441,872	0	274,872	95,905
May		2,124,396	694,142	45,763	59,660	480,508	0	306,630	404,561
June		2,489,998	825,527	49,550	51,656	499,608	0	307,934	626,162
July		2,693,943	905,037	68,381	54,625	534,811	0	331,390	659,225
August		2,539,124	925,686	58,587	54,394	510,903	0	305,645	548,187
September		2,298,797	782,224	51,458	53,202	517,338	0	300,387	459,381
October		1,711,137	724,877	42,229	47,510	401,689	0	286,677	72,414
November		1,894,600	917,233	53,999	50,635	443,672	0	282,756	7,257
December		1,988,349	1,026,527	52,617	48,228	427,553	0	293,064	1,579
Total		25,579,720	10,677,792	623,387	615,864	5,595,659	0	3,533,754	2,882,262
Ratio		1.0000	0.4174	0.0244	0.0241	0.2188	0.0000	0.1381	0.1127
Growth Related Monthly Coincident Demands 2009 less 2004 (Idaho Power's 2004 IRP Sales and Load Forecast pages 33-41)									
2004			513	417	417	417	417	263	195
2009			568	496	496	496	496	307	198
Percenct Growth			10.72%	18.94%	18.94%	18.94%	18.94%	16.73%	1.54%
Generation Demand Related Weightings									
January	0.05	14,430	5,925	537	474	4,280	0	2,380	1
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	5.81	1,501,429	432,384	50,371	65,667	528,893	0	298,049	36,162
June	15.34	4,272,967	1,357,694	143,999	150,120	1,451,930	0	790,278	147,774
July	13.29	4,034,271	1,289,545	172,168	137,533	1,346,531	0	736,820	134,786
August	10.47	3,065,433	1,039,096	116,209	107,892	1,013,389	0	535,378	88,300
September	6.84	1,878,911	573,631	66,681	68,941	670,381	0	343,743	48,341
October	0.00	0	0	0	0	0	0	0	0
November	1.43	380,079	140,625	14,629	13,718	120,196	0	67,646	160
December	5.77	1,588,723	635,026	57,517	52,719	467,366	0	282,901	140
Total		16,736,244	5,473,926	622,110	597,063	5,602,966	0	3,057,197	455,664
Ratio		1.0000	0.3271	0.0372	0.0357	0.3348	0.0000	0.1827	0.0272
Total Ratio		1.0000	0.3723	0.0308	0.0299	0.2768	0.0000	0.1604	0.0700

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005
Normalized Demands

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,095	0	994	1,952,686	35,749	23,547	81,026	140,322
February		2,063	0	994	1,918,357	33,676	23,796	80,796	138,268
March		2,078	0	994	1,761,021	32,106	24,106	80,884	137,096
April		2,062	0	994	1,655,850	30,757	23,868	81,151	135,776
May		2,058	0	994	1,994,316	21,708	23,308	85,064	130,080
June		2,093	0	1,024	2,363,554	24,338	16,229	85,877	126,444
July		2,096	0	1,024	2,556,589	25,030	23,155	89,169	137,354
August		2,095	0	1,024	2,406,521	22,135	23,097	87,371	132,603
September		2,108	0	1,024	2,167,122	22,313	22,093	87,269	131,675
October		2,096	0	1,024	1,578,516	27,162	22,848	82,611	132,621
November		2,121	0	1,024	1,758,697	29,977	23,310	82,616	135,903
December		2,116	0	1,024	1,852,708	29,952	23,779	81,910	135,641
Total		25,081	0	12,138	23,965,937	334,903	273,136	1,005,744	1,613,783
Ratio		0.0010	0.0000	0.0005	0.9369	0.0131	0.0107	0.0393	0.0631
Monthly Coincident Demands Weighted by Marginal Demand Costs									
		417	417	417		131	131	131	
		496	496	496		146	146	146	
		18.94%	18.94%	18.94%		11.45%	11.45%	11.45%	
January	0.05	20	0	9	13,627	205	135	464	803
February	0.00	0	0	0	0	0	0	0	0
March	0.00	0	0	0	0	0	0	0	0
April	0.00	0	0	0	0	0	0	0	0
May	5.81	2,265	0	1,094	1,414,891	14,442	15,506	56,590	86,538
June	15.34	6,083	0	2,976	4,050,869	42,749	28,506	150,842	222,097
July	13.29	5,277	0	2,578	3,825,252	38,090	35,236	135,693	209,019
August	10.47	4,155	0	2,031	2,906,462	26,537	27,690	104,745	158,972
September	6.84	2,732	0	1,327	1,775,783	17,476	17,303	68,350	103,129
October	0.00	0	0	0	0	0	0	0	0
November	1.43	575	0	277	357,826	4,908	3,817	13,528	22,253
December	5.77	2,313	0	1,119	1,499,107	19,789	15,710	54,117	89,616
Total		23,420	0	11,412	15,843,817	164,195	143,904	584,329	892,427
Ratio		0.0014	0.0000	0.0007	0.9467	0.0098	0.0086	0.0349	0.0533
Total Ratio		0.0012	0.0000	0.0006	0.9418	0.0115	0.0096	0.0371	0.0582

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005
Normalized Demands with Weights Only Applied to Future Growth

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January		2,093,008	1,105,285	56,693	50,045	451,865	0	284,520	1,189
February		2,056,625	1,063,727	54,611	49,445	455,984	0	290,191	1,342
March		1,898,117	961,888	43,884	47,573	429,856	0	269,688	5,060
April		1,791,626	745,639	45,615	48,891	441,872	0	274,872	95,905
May		2,124,396	694,142	45,763	59,660	480,508	0	306,630	404,561
June		2,489,998	825,527	49,550	51,656	499,608	0	307,934	626,162
July		2,693,943	905,037	68,381	54,625	534,811	0	331,390	659,225
August		2,539,124	925,686	58,587	54,394	510,903	0	305,645	548,187
September		2,298,797	782,224	51,458	53,202	517,338	0	300,387	459,381
October		1,711,137	724,877	42,229	47,510	401,689	0	286,677	72,414
November		1,894,600	917,233	53,999	50,635	443,672	0	282,756	7,257
December		1,988,349	1,026,527	52,617	48,228	427,553	0	293,064	1,579
Total		25,579,720	10,677,792	623,387	615,864	5,595,659	0	3,533,754	2,882,262
Actual	D13	1.0000	0.4174	0.0244	0.0241	0.2188	0.0000	0.1381	0.1127
Growth Related Monthly Coincident Demands 2009 less 2004 (Idaho Power's 2004 IRP Sales and Load Forecast pages 33-41)									
2004			513	417	417	417	417	263	195
2009			568	496	496	496	496	307	198
Percenct Growth			10.72%	18.94%	18.94%	18.94%	18.94%	16.73%	1.54%
Transmission Related Weightings									
January	2.98	860,025	353,131	32,006	28,253	255,103	0	141,849	55
February	2.04	581,656	232,651	21,106	19,109	176,226	0	99,040	42
March	2.94	774,296	303,192	24,442	26,497	239,421	0	132,650	229
April	2.09	512,356	167,078	18,061	19,358	174,958	0	96,111	3,084
May	6.57	1,697,830	488,944	56,960	74,257	598,077	0	337,037	40,892
June	11.83	3,295,254	1,047,035	111,050	115,770	1,119,709	0	609,452	113,961
July	11.22	3,405,908	1,088,691	145,351	116,112	1,136,800	0	622,056	113,792
August	9.51	2,784,362	943,821	105,554	97,999	920,471	0	486,289	80,204
September	6.40	1,758,046	536,731	62,391	64,506	627,257	0	321,631	45,231
October	1.66	391,211	129,008	13,280	14,941	126,325	0	79,616	1,849
November	3.57	948,869	351,070	36,521	34,246	300,069	0	168,880	399
December	6.19	1,704,367	681,250	61,703	56,556	501,385	0	303,494	150
Total		18,714,112	6,322,601	688,427	667,605	6,175,801	0	3,398,103	399,888
Weighted	D13	1.0000	0.3379	0.0368	0.0357	0.3300	0.0000	0.1816	0.0214
Average	D13	1.0000	0.3776	0.0306	0.0299	0.2744	0.0000	0.1599	0.0670

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005
Normalized Demands

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
CAPACITY RELATED ALLOCATION FACTORS									
Monthly Coincident Demands @ Generation Level									
January	0.00	2,095	0	994	1,952,686	35,749	23,547	81,026	140,322
February	0.00	2,063	0	994	1,918,357	33,676	23,796	80,796	138,268
March	0.00	2,078	0	994	1,761,021	32,106	24,106	80,884	137,096
April	0.00	2,062	0	994	1,655,850	30,757	23,868	81,151	135,776
May	0.00	2,058	0	994	1,994,316	21,708	23,308	85,064	130,080
June	0.00	2,093	0	1,024	2,363,554	24,338	16,229	85,877	126,444
July	0.00	2,096	0	1,024	2,556,589	25,030	23,155	89,169	137,354
August	0.00	2,095	0	1,024	2,406,521	22,135	23,097	87,371	132,603
September	0.00	2,108	0	1,024	2,167,122	22,313	22,093	87,269	131,675
October	0.00	2,096	0	1,024	1,578,516	27,162	22,848	82,611	132,621
November	0.00	2,121	0	1,024	1,758,697	29,977	23,310	82,616	135,903
December	0.00	2,116	0	1,024	1,852,708	29,952	23,779	81,910	135,641
Total		25,081	0	12,138	23,965,937	334,903	273,136	1,005,744	1,613,783
Actual	D13	0.0010	0.0000	0.0005	0.9369	0.0131	0.0107	0.0393	0.0631
Monthly Coincident Demands Weighted by Marginal Demand Costs									
		417	417	417		131	131	131	
		496	496	496		146	146	146	
		18.94%	18.94%	18.94%		11.45%	11.45%	11.45%	
Transmission Related Weightings									
January	2.98	1,183	0	561	812,144	12,198	8,035	27,648	47,881
February	2.04	797	0	384	549,358	7,866	5,558	18,873	32,298
March	2.94	1,157	0	554	728,144	10,808	8,115	27,229	46,152
April	2.09	816	0	394	479,863	7,361	5,712	19,420	32,493
May	6.57	2,562	0	1,237	1,599,972	16,331	17,534	63,993	97,858
June	11.83	4,691	0	2,295	3,123,976	32,968	21,983	116,327	171,279
July	11.22	4,455	0	2,177	3,229,445	32,157	29,748	114,558	176,463
August	9.51	3,774	0	1,845	2,639,966	24,103	25,151	95,141	144,396
September	6.40	2,556	0	1,242	1,661,551	16,352	16,190	63,953	96,495
October	1.66	659	0	322	366,003	5,163	4,343	15,702	25,208
November	3.57	1,434	0	693	893,315	12,254	9,529	33,772	55,554
December	6.19	2,481	0	1,201	1,608,227	21,229	16,854	58,056	96,139
Total		26,567	0	12,903	17,691,964	198,790	168,753	654,673	1,022,215
Weighted	D13	0.0014	0.0000	0.0007	0.9454	0.0106	0.0090	0.0350	0.0546
Average	D13	0.0012	0.0000	0.0006	0.9411	0.0119	0.0098	0.0372	0.0589

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005
Normalized Demands with Weights Only Applied to Future Growth

Month	Marginal Cost	Total IPUC Jurisdiction	Residential (1)	General Service (7)	General Service (9-Primary)	General Service (9-Secondary)	Area Lighting (15)	Large Power Service (19-Primary)	Irrigation Service (24-Secondary)
ENERGY RELATED ALLOCATION FACTORS									
Monthly Energy Requirements @ Generation Level									
January		1,186,915	558,946	33,029	30,155	272,254	545	189,249	868
February		1,025,701	466,931	27,754	27,127	242,046	541	168,169	885
March		1,009,955	425,522	26,649	28,872	248,645	544	176,882	3,695
April		994,084	360,538	23,979	29,417	241,889	543	173,531	67,769
May		1,146,274	331,471	23,056	30,556	249,145	539	180,527	232,537
June		1,324,549	333,213	25,188	27,708	262,648	557	186,769	399,565
July		1,485,659	419,410	28,798	30,400	283,834	554	196,519	426,161
August		1,403,041	417,039	29,028	31,314	286,691	547	194,231	345,800
September		1,118,131	319,447	24,144	29,942	255,186	557	186,648	209,243
October		1,013,513	355,867	25,425	29,615	259,883	548	192,571	52,875
November		1,048,579	455,328	28,889	28,802	252,928	557	180,308	5,128
December		1,194,124	562,207	33,719	30,813	277,104	551	186,531	1,153
Total		13,950,525	5,005,919	329,658	354,721	3,132,253	6,583	2,211,935	1,745,679
Ratio		1.0000	0.3588	0.0236	0.0254	0.2245	0.0005	0.1586	0.1251
Growth Related Monthly Coincident Demands 2009 less 2004 (Idaho Power's 2004 IRP Sales and Load Forecast pages 33-41)									
2004			513	417	417	417	417	263	195
2009			568	496	496	496	496	307	198
Percenct Growth			10.72%	18.94%	18.94%	18.94%	18.94%	16.73%	1.54%
Generation Energy Related Weightings									
January	36.65	6,128,291	2,196,287	229,330	209,375	1,890,337	3,784	1,160,391	489
February	28.61	4,160,446	1,432,240	150,430	147,032	1,311,918	2,932	804,935	390
March	41.19	5,957,888	1,879,140	207,952	225,299	1,940,272	4,245	1,218,912	2,341
April	31.54	4,292,818	1,219,153	143,279	175,773	1,445,336	3,245	915,663	32,884
May	35.73	4,943,003	1,269,767	156,066	206,833	1,686,461	3,648	1,079,126	127,824
June	43.04	6,175,285	1,537,586	205,379	225,927	2,141,595	4,542	1,344,850	264,574
July	55.92	9,016,381	2,514,498	305,085	322,056	3,006,925	5,869	1,838,521	366,630
August	45.44	7,267,592	2,031,703	249,889	269,568	2,467,990	4,709	1,476,569	241,741
September	43.72	6,047,922	1,497,353	199,977	248,000	2,113,625	4,613	1,365,213	140,740
October	41.22	5,866,522	1,572,682	198,545	231,265	2,029,443	4,279	1,327,993	33,531
November	44.69	6,675,723	2,181,625	244,587	243,851	2,141,402	4,716	1,348,101	3,526
December	43.77	7,366,991	2,638,263	279,603	255,506	2,297,790	4,569	1,365,918	776
Total		73,898,863	21,970,298	2,570,123	2,760,485	24,473,096	51,152	15,246,192	1,215,445
Ratio		1.0000	0.2973	0.0348	0.0374	0.3312	0.0007	0.2063	0.0164
Total Ratio		1.0000	0.3281	0.0292	0.0314	0.2778	0.0006	0.1824	0.0708

IDAHO POWER COMPANY
DEVELOPMENT OF WEIGHTED DEMAND AND ENERGY ALLOCATORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005
Normalized Demands

Month	Marginal Cost	Unmetered Service (40)	Municipal Street Light (41)	Traffic Control (42)	Total Tariff Customers	DOE/INL	Simplot	Micron	Total Special Contracts
ENERGY RELATED ALLOCATION FACTORS									
Monthly Energy Requirements @ Generation Level									
January		1,501	1,718	712	1,088,977	21,508	17,352	59,078	97,938
February		1,475	1,716	712	937,356	19,022	15,824	53,499	88,345
March		1,489	1,723	712	914,733	18,452	17,659	59,111	95,222
April		1,477	1,736	712	901,591	18,186	17,019	57,288	92,493
May		1,474	1,745	712	1,051,762	17,513	17,384	59,615	94,512
June		1,500	1,705	734	1,239,587	16,560	9,994	58,408	84,962
July		1,501	1,726	734	1,389,637	16,829	17,211	61,982	96,022
August		1,501	1,726	734	1,308,611	15,732	17,002	61,696	94,430
September		1,511	1,726	734	1,029,138	14,076	16,193	58,724	88,993
October		1,502	1,725	734	920,745	15,525	17,166	60,077	92,768
November		1,520	1,746	734	955,940	17,595	16,774	58,270	92,639
December		1,516	1,752	734	1,096,080	20,907	17,436	59,701	98,044
Total		17,967	20,744	8,698	12,834,157	211,905	197,014	707,449	1,116,368
Ratio		0.0013	0.0015	0.0006	0.9200	0.0152	0.0141	0.0507	0.0800
Monthly Coincident Demands Weighted by Marginal Demand Costs									
		417	417	417		131	131	131	
		496	496	496		146	146	146	
		18.94%	18.94%	18.94%		11.45%	11.45%	11.45%	
January	36.65	10,422	11,929	4,944	5,717,288	90,260	72,819	247,925	411,003
February	28.61	7,995	9,301	3,859	3,871,032	62,315	51,839	175,260	289,414
March	41.19	11,619	13,445	5,556	5,508,782	87,027	83,287	278,792	449,106
April	31.54	8,825	10,373	4,254	3,958,784	65,678	61,463	206,893	334,034
May	35.73	9,977	11,812	4,820	4,556,334	71,650	71,122	243,898	386,670
June	43.04	12,231	13,902	5,985	5,756,572	81,612	49,253	287,849	418,713
July	55.92	15,902	18,285	7,776	8,401,547	107,757	110,203	396,874	614,834
August	45.44	12,921	14,858	6,319	6,776,267	81,854	88,462	321,008	491,324
September	43.72	12,515	14,296	6,079	5,602,413	70,466	81,064	293,979	445,508
October	41.22	11,729	13,471	5,732	5,428,672	73,276	81,021	283,554	437,851
November	44.69	12,869	14,782	6,214	6,201,673	90,037	85,836	298,178	474,050
December	43.77	12,571	14,528	6,086	6,875,611	104,782	87,386	299,211	491,380
Total		139,577	160,982	67,624	68,654,975	986,713	923,754	3,333,420	5,243,888
Ratio		0.0019	0.0022	0.0009	0.9290	0.0134	0.0125	0.0451	0.0710
Total Ratio		0.0016	0.0018	0.0008	0.9245	0.0143	0.0133	0.0479	0.0755

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 1st day of March, 2006, I served a true, correct and complete copy of the foregoing document, to each of the following by e-mail and/or mail:

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