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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS RULE H LINE EXTENSION TARIFF RELATED TO NEW SERVICE ATTACHMENTS AND DISTRIBUTION LINE INSTALLATIONS.	**CASE NO. IPC-E-08-22** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Kristine A. Sasser, Deputy Attorney General, and in response to the Notice of Modified Procedure and Notice of Scheduling issued in Order No. 30719 on January 21, 2009, in Case No. IPC-E-08-22, submits the following comments.

BACKGROUND

On October 30, 2008, Idaho Power Company filed an Application with the Commission seeking authority to modify its Rule H tariff relating to new service attachments and distribution line installations and alterations. Specifically, the Company wishes to update line installation charges and allowances, thereby shifting more of the cost burden for new service attachments and distribution line installations or alterations from general ratepayers to new customers requesting construction for these services. The tariff has also been extensively reworded and formatted to make it easier to read and understand. Idaho Power also proposes to update its charges and credits in its Rule H tariff on an annual basis.

STAFF ANALYSIS

Before beginning further discussion, Staff believes it would be helpful to define terminology used in discussing line extension policies. Several important and frequently used terms are defined below.

> Distribution system or distribution refers to that portion of the delivery system closest to the customer with voltages under 44 kV. The distribution system includes line extensions and terminal facilities.
>
> Line extension is any installation of new distribution facilities (excluding relocations) or alteration of existing distribution facilities owned by the Company other than terminal facilities.
>
> Terminal facilities include transformer, meter and service cable.
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> Service, services, or service cable refers to the conductor providing usable voltage to the customer meter from, typically, the Company's last pole, junction box or transformer. The service cable may be overhead or underground.

Staff believes it may also be helpful before continuing further to discuss some general policies and practices related to distribution plant cost recovery since it differs somewhat from generation and transmission plant. The capital cost of installing new generation and transmission plant has always generally been recovered through rates paid by all customers. Hook-up fees, impact fees, or other charges at the time a new customer begins taking service have never been charged for the purpose of recovering the costs of building new generation and transmission facilities. In fact, in accordance with prior decisions of the Idaho Supreme Court, such fees cannot be charged for new plant that cannot be attributed specifically to serving new customers.[1]

In the case of distribution plant, however, it is possible to associate specific facilities with specific customers who use them. For example, meters are physically attached to customers' buildings, service lines run directly to each customer's premises, and transformers serve a specific customer or group of customers. Even most distribution lines can be associated with serving

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[1] *Building Contractors Association v. IPUC and Boise Water Corporation,* 128 Idaho 534, 916 P.2d 1259 (1996); *Idaho State Homebuilders vs. Washington Water Power,* 107 Idaho 415, 690 P.2d 350 (1984).

specific subdivisions, businesses along a street or specific neighborhoods. Because of this, the costs of new distribution plant have, throughout most of Idaho Power's history, been recovered in two ways — partially through up-front capital contributions from new customers, and partially through electric rates charged to all customers. Up-front charges are either based on estimates prepared by Idaho Power for each line extension job (work order costs), or are specified in the Rule H tariff for standard tasks or materials. The portion collected through electric rates represents the investment in new facilities made by Idaho Power. It is often referred to as an "allowance."

Allowances

Idaho Power proposes to reduce line extension allowances for nearly all customer classes. The underlying rationale behind the Company's proposal is that growth should pay for itself, and that by reducing allowances and refunds, one cause of upward pressure on electric rates will be relieved. Although Staff agrees in principle with the Company's rationale, Idaho Power has done no analysis to prove that growth is not paying for itself, nor has the Company done any analysis to determine specifically what amounts of allowances and refunds can alleviate upward pressure on rates. Idaho Power's position seems to be that because it has filed four general rate cases within the past six years and has added two gas-fired peaking plants in the same timeframe, that new customer growth is causing upward pressure on rates. The Company concludes that a reduction in Company investment in new distribution plant is necessary and proposes a reduction in allowances based strictly on policy without supporting analysis.

Staff agrees with Idaho Power that new customer growth, combined with the effects of inflation, do indeed cause upward pressure on rates. Staff also supports a policy to reduce upward pressure on rates, justified by sound analysis. A much more complete discussion and analysis of the effects of new customer growth and inflation is presented in Attachment No. 1.

Staff believes that the goal in setting allowance and refund amounts for distribution line extensions should be to eliminate the impact on existing electric rates. More specifically, Staff believes the line extension rules should provide a new customer allowance (Company investment) that can be supported by electric rates paid by that customer over time. If the line extension costs exceed the allowance, then the new customer would pay an up-front contribution for the difference rather than including the excess costs in electric rates paid by all customers. In order to properly establish an allowance, a refund and the potential for additional customer contribution, a detailed analysis of distribution investment embedded in existing electric rates must be conducted.

Staff's Approach to Computing Allowances

The Company's investment has traditionally been provided as an allowance towards the cost of new facilities. Staff's approach to determining a Company-provided allowance for service connections and line extensions was to determine what equivalent investment the Company can make that will be supported by the revenue stream embedded in the Company's current rates. Attachment No. 2 details the approximate size of that investment for residential, small commercial, large commercial, irrigation and industrial classes. All calculations assume average consumption levels for customers within each class. Staff used the Commission's last rate Order in Case No. IPC-E-08-10 as the basis of the calculations. Assumptions used in making the calculations are provided in Attachment 3. Staff also used the cost of service study accepted by the Commission in Case IPC-E-08-10 as a basis for calculations. A summary of the cost of service figures used in the analysis is included as Attachment 4.

The equivalent investment per residential customer is calculated using the cost of service study and capital structure accepted by the Commission. Attachment 5 summarizes the calculation of the investment for the residential class. The net distribution plant and terminal facility value of $1104.12 per customer (plant in service less accumulated depreciation and amortization) is used to calculate the revenue requirement associated with the return on common equity grossed up to recognize the income taxes associated with the return ($1104.12 x (0.05173 x 1.642) = $94.36). Debt service costs (0.03007 x $1104.12 = $33.20) are added to the equity return and tax calculation to produce the total revenue requirement associated with the cost of capital and associated income taxes of $127.56. Depreciation expense of $45.26 (actual distribution plant and terminal facilities depreciation expense per customer) is added to the capital and tax cost to produce a total revenue requirement related to distribution plant and terminal facilities of $172.25.

This revenue stream is embedded in the Company's current sales rate structure. Staff used this revenue stream to calculate the new Company investment that can be supported by current rates without applying either upward or downward pressure on the Company's rate structure. The revenue stream represents the total cost of capital, with associated taxes, plus depreciation expenses associated with the Company's distribution plant and terminal facilities. Because the actual depreciation expense is based upon a gross investment greater than the net plant investment built into rates, it follows that the new investment can be an amount larger than the current embedded net investment. The composite of the total cost of capital and associated taxes expressed as a percentage of rate base is 11.501 percent. The composite depreciation rate for distribution and terminal facilities is 2.47 percent. The combined total of these two percentages (13.971 percent) represents the relationship of the current revenue stream to new gross investment. Dividing the revenue stream of $172.25 by 13.971 percent produces the revenue neutral investment of $1232.44, which Idaho Power can make to provide service to new residential customers.

Attachment No. 6 summarizes similar calculations for other customer classes.

Even though the Company's embedded investment is split between investment in distribution plant and terminal facilities, Staff recommends that all of the recommended Company investment be applied to the cost of providing terminal facilities. Staff maintains that it is only important that the total value of the Company's investment be equal to the total embedded cost — not that the Company's investment be applied to both terminal facilities and distribution facilities in the exact proportion as are their embedded costs. Terminal facilities are defined as a transformer, meter, and service drop. Staff's estimates of the cost of terminal facilities are shown in Attachment No. 7.

Staff's Recommended Allowances

Residential

Staff recommends an allowance of terminal facilities for the residential customer class. Because the average investment for existing customers ($1,232) is fairly close to Staff's estimate of the cost of overhead terminal facilities ($1,444), Staff believes terminal facilities should be provided at no cost to the residential customer. Even though the allowance cost of terminal facilities is slightly more than the average investment, Staff believes that simplicity, both to the Company and the customer, is important. Moreover, within the residential class (and all other classes too) there is wide variation between customers. Obviously, some customers will generate much less revenue than the class average and others will generate much more. Consequently, instead of precisely matching the recommended allowance with the average embedded investment for the class, Staff believes good judgment and simplicity support an allowance of terminal facilities.

Under the present tariff, the allowance is equal to terminal facilities plus an amount ranging from $800 to $1,300 depending on whether the customer is in a subdivision and whether the home is all-electric or gas-heated. In this case, Staff does not recommend that any amount beyond the cost of terminal facilities be included as an allowance. Staff also does not recommend a different allowance amount based on whether a customer has gas or electric heat. Gas has become the predominant heating choice where it is available because it is generally cheaper and more efficient. Staff does not wish to encourage electric heat by offering a higher allowance.

For new residential homes outside of subdivisions, Idaho Power proposes an allowance of $1,780 per customer, which it calculates to be the cost of standard overhead terminal facilities. Staff's proposed allowance is similar, but expressed as the cost of terminal facilities rather than a fixed dollar amount. Staff has no objection to stating the allowance in the tariff as a fixed dollar amount, however, as long as the amount is updated through an annual filing.

Because terminal facilities costs in residential subdivisions are different than for individual residences and because of other factors unique to subdivisions, Staff's proposed allowances for subdivisions will be addressed separately.

Subdivisions

Staff believes that homeowners or individual builders who request new service within subdivisions are entitled to the same allowances for terminal facilities as are other customers not located in subdivisions. Staff's proposed allowance for all residential customers is the cost of overhead terminal facilities.

However, transformers, one component of the proposed terminal facilities allowance, are generally installed prior to building within the subdivision, at the same time as line extensions are completed. On the other hand, installation of the other components of terminal facilities, a service attachment and a meter, is generally requested by the homeowner or builder at the time of building construction, not by the subdivider at the time the subdivision is developed. Consequently, in order to be consistent and provide all residential customers comparable allowances, Staff proposes that subdividers pay all line extension costs, including transformer costs, but that transformer costs be subject to refund to the subdivider as new homes are built and customers are connected. Homeowners and builders would receive standard service attachments and meters at no cost. Making transformer costs subject to refund as individual lots are developed insures that all residential customers receive equal allowances, but relieves the Company of the risk of bearing the cost of transformers should lots not be developed. If transformer costs are not subject to refund, there is a possibility that the Company will have invested in facilities intended to be paid through rates, but have no customers generating revenue through rates. This refund method puts the risk of development on the subdivision developer rather than on Idaho Power's ratepayers. Because of the current economic situation, Staff believes that the risk of subdivisions progressing as planned is now greater than ever. Staff believes it would be inappropriate for ratepayers to bear any investment risk in new facilities installed to serve speculative developments.

Refunds for transformers would be made to subdividers as each new customer is connected. The amount of the refund should represent the installed cost of the transformer needed to serve the new customer. Where single transformers serve multiple customers, the amount of the refund should be equal to the total cost of the transformers installed in the subdivision divided by the total number of lots in the subdivision.

Transformer refunds under Staff's proposal would not replace the $800 residential subdivision refund which is currently offered under the present policy. Transformer refunds are not intended to be a substitute for the current refund amount, nor are they intended to have equivalent value. They are a portion of the terminal facilities allowance paid when a new customer takes service and are simply a means of relieving Idaho Power and its ratepayers of investment risk.

Small Commercial

The small commercial class (Schedule 7) is very similar to the residential class in terms of required distribution and terminal facilities. In fact, Staff assumes that the cost of terminal facilities is only slightly higher than for residential customers, since commercial customers are demand metered. However, on average, small commercial customers' energy usage is less than the residential customer class. Consequently, Idaho Power's embedded investment per customer is less for small commercial customers than for residential customers. As a result, Staff recommends that the allowance for Schedule 7 customers be set at 60 percent of the cost of overhead terminal facilities for single phase service. Staff proposes that small commercial customers who require three phase service be required to pay all additional costs above the allowance amount for single phase customers.

Large Commercial, Irrigation

For the large commercial and irrigation classes (Schedules 9 and 24 respectively), the embedded Company investment per customer exceeds Staff's estimated cost of terminal facilities in all cases. Consequently, for all customers in both of these classes, Staff recommends that an allowance equal to the cost of overhead terminal facilities be provided by the Company and that no allowance be offered toward line extension costs.

Staff recommends an allowance equivalent to the cost of overhead terminal facilities for all large commercial and irrigation customers whether they require single or three phase service. Most of these customers typically require three phase service, and the embedded investment can support the cost of three phase facilities. Single phase large commercial and irrigation customers generate less revenue and have a lower embedded investment, but they also require less expensive terminal facilities. Therefore, Staff believes an allowance of terminal facilities is reasonable for both single and three phase service.

Industrial

Under the current Rule H, allowances for industrial (Schedule 19) customers are determined on a case-by-case basis due to the wide diversity in both customer usage and needed distribution facilities. Both Idaho Power and Staff propose to continue to determine allowances for industrial customers on a case-by-case basis.

Staff's proposed allowances for all customer classes are summarized in Attachment No. 8.

Underground Service

Staff's proposed allowances are based on the cost to provide an overhead service attachment. For residential (Schedule 1) and small commercial (Schedule 7) customers, the Company should provide underground service at no additional charge if the customer supplies the trench, backfill, conduit and compaction per Company specifications. Otherwise, customers requesting underground service should be required to pay the difference between the cost of providing underground service and the cost of providing overhead service. The overhead-underground differential should not be subject to refund. Line extension costs associated with Company betterments should continue to be the Company's responsibility and not chargeable to the customer.

Examples

Staff prepared several examples of hypothetical cases to compare the existing Rule H to the Company's proposal and to Staff's proposal. These examples are included as Attachment No. 9. None of the examples are intended to be representative of all cases for an entire customer class. Their purpose is simply to illustrate how the proposed allowances and refunds would affect customers and to give a general indication of how costs would be shifted. In each of the examples, all customers would receive an allowance of terminal facilities, but none of the customers would receive an allowance for line extension work upstream of the customer's transformer.

The first example is for a residential line extension not located in a subdivision. Under the proposed new Rule H, the net payment by the customer would be greater than under the existing rule, but the entire payment is still subject to refund. The difference in the net payment is due entirely to the reduction of the allowance offered under the current rule. The size of the allowance under the current rule is overhead terminal facilities plus $1000 for residences without electric space or water heating and $1300 for residences with electric space and water heating.

The second example compares costs under both the existing and proposed rules for five actual subdivisions which were completed in recent years. In each of the five cases, costs are higher under the proposed rule than under the existing rule due to reduced allowances. Note that the only difference between Idaho Power's and Staff's proposals is that Idaho Power proposes that an allowance for transformers be applied against the work order cost initially, whereas Staff proposes that refunds for transformers be given at the time service is provided to each lot. This example also illustrates how much work order costs can vary from one subdivision to the next.

The third and fourth examples are for commercial and irrigation line extensions, respectively. In the irrigation example, Idaho Power's proposal would result in a higher overall cost for this customer because the customer requires terminal facilities that are more expensive than the standard three-phase overhead terminal facilities allowance proposed by the Company. Under Staff's proposal, there would be no change from the current Rule H.

In the commercial example, the customer would pay more under Idaho Power's proposal, again because this customer's terminal facilities are more costly than "standard" three-phase overhead terminal facilities. Under Staff's proposal, allowances for the large commercial class would be greater than they currently are under the existing rule; consequently, most customers would likely see a reduction in the overall cost of line extensions.

Because Staff's proposed allowances for the residential, large commercial and irrigation customer classes are in terms of terminal facilities rather than in terms of dollar amounts as proposed by Idaho Power, the allowances will change over time as costs increase due to inflation. If the Commission chooses to accept Staff's proposal for allowances, Staff recommends that Idaho Power be required to annually submit "standard" terminal facilities costs to the Commission so that Staff can track changes in costs and address complaints and inquiries it receives regarding Rule H.

Work Order Cost Method and Controls

Currently under Rule H, the Company charges line extension costs to the customer based on work order cost estimates. Work order cost estimates are prepared by the Company before construction. It is Staff's understanding that Idaho Power does not, except in the case of unusual conditions, adjust work order costs after construction has been completed to reflect actual installation costs, and modify the customer's bill accordingly.

Based on a study of 2008 line extension work orders[2], the Company's own analysis indicates that 43 percent of work order cost estimates differed from actual costs by at least 15 percent and more than $800. In other words, estimated costs significantly differed from actual costs much of the time. Staff obtained a confidential Sarbannes-Oxley report, covering work order controls for work orders involving contributions in aid of construction. On page 3 of the report this statement appears, "...there is not a work order review process that validates the estimated cost is appropriate at the time the estimate is developed." When the Company bills customers for estimated costs rather than actual costs, some customers may be either overbilled or underbilled substantially. For 2008, the total actual costs exceeded the amounts collected from customers by $5.6 million (12.2%). It should be pointed out, however, that some of this

[2] Control #6 Work Order Estimated Costs Versus Actual Costs, January 21, 2009; Memo from Ben Hendry to Rick Schweitzer and Warren Kline; report prepared to satisfy Sarbannes-Oxley requirements.

difference is due to work order estimates that were prepared but never built and also because customer cost quotes only include general overheads at 1.5 percent while the actual overhead incurred by Idaho Power is 15.75 percent. Nevertheless, Staff is concerned that not enough contributions in aid of construction were collected for 2008, and that this significant under-collection may have been made up by other ratepayers. Staff recommends that a more thorough audit be conducted to better quantify and define this problem, and that Staff and the Company work jointly to propose improvements in the process if significant problems are identified.

Purchasing Procedures

Staff interviewed employees of Idaho Power representing the purchasing department. Its purchasing procedure is called "Strategic Sourcing Process" and has five steps. According to these employees, the design of and controls over this process are intended to comply with Sarbannes-Oxley requirements. These controls are tested by internal and external auditors. Staff believes these procedures appear to be well considered and appropriate.

Staff reviewed current RFPs and a purchase contract for several items involved in the current request for tariff changes. These items included meters, several sizes of transformers and 350 cable. A review of the quoted and contracted prices for these items demonstrates wide variances in practices among suppliers. In addition, quoted prices for some items are contractually tied to external commodity indexes. In the case of 350 cable those indexes are an aluminum index and a copper index. These pricing strategies are designed to protect suppliers from losses resulting from volatile or increasing commodity prices. During periods of increasing commodity prices, cumulative increases can occur. This can result in prices changes, which are seen as "spikey" or unusually large.

The amounts seen in work order charges may be additive combinations of quoted prices, delivery charges and inventory costs. For inventory items such as meters or transformers, Idaho Power uses a cost averaging method which averages costs of current inventory with costs of new purchases.

General Overhead Rate

Staff reviewed the cost allocation formula for current rates. Staff believes Rule H overhead costs are in current electric rates to the extent they exceed the 1.5 percent limitation.

Including the entire overhead rate in Rule H work orders would result in Idaho Power collecting the difference of 13.5 percent in both work orders and in current electricity rates. Staff believes this is a timing problem, which can be resolved in the next rate case. The case would set rates based on costs which do not include that portion of construction overhead belonging to Rule H work orders. Simultaneously, the overhead rate for Rule H could include the 15 percent, effective on the same day as the new rates. This would shift costs from general rates to those requesting Rule H line extensions.

Vested Interest Refund Period

Idaho Power proposes to reduce the time limitation to receive vested interest refunds from five years to four years. In support of its position, the Company cites a reduction in administrative burden and points out that less than two percent of customers eligible for vested interest refunds receive them in the fifth year.

Staff does not believe Idaho Power has made a convincing case for reducing the refund period, and, in fact, Staff believes the Company's rationale is somewhat contradictory. If very few refunds are actually made in the fifth year as Idaho Power contends, it does not seem reasonable that tracking these refunds would present a significant administrative burden. Moreover, in the future, Staff believes that more refunds will be made in the fifth year now that building activity has slowed from the rapid pace of the past several years and subdivisions are slower to fill.

Idaho Power also proposes that subdividers be eligible for vested interest refunds inside subdivisions for additional line installations that were not part of the initial line installation. Staff does not object to this proposed change.

Updated Charges

Idaho Power proposes to update several charges in Rule H including engineering charges, underground service attachment charges, overhead and underground temporary service attachment charges, and overhead and underground temporary service return trip charges. Staff has reviewed the proposed updated charges and believes they are reasonable based on changes in labor rates, different installation procedures and changes in calculation methodology.

Formatting Changes

Idaho Power proposes to make formatting changes to Rule H to make the tariff easier to read and administer. Staff supports the proposed formatting changes.

Changes to Definitions and General Provisions

Idaho Power proposes to add several definitions to clarify discrepancies and identify terms missing from the current tariff. Staff supports the addition of all of the proposed definitions, with the exception of the removal of the 1.5 percent limitation for recovery of general overheads as discussed earlier in these Staff comments.

For clarification purposes, the Company also proposes several modifications to the General Provisions section of the tariff. Staff has no objection to these proposed modifications.

Staff does recommend two changes to the tariff provisions related to unusual conditions. The current definition of "Unusual Conditions" has caused some confusion, which resulted in complaints being filed with the Commission. The confusion stems in part from the reference to "construction conditions not normally encountered."

For example, if construction is to take place in an area that is commonly known to be rocky, a customer requesting service would consider rock digging to be a normally encountered condition. To that customer, an unusual condition would be something above and beyond the normal rocky condition one would expect to encounter in that location. The customer then anticipates receiving a refund of the amount paid for unusual conditions when no out-of-the ordinary conditions are encountered. However, the Company's cost estimating process excludes the cost for rock digging and other "unusual conditions" when average Company-wide costs are calculated. From the Company's perspective, any cost associated with rock digging is project-specific ("not normally encountered") and will always be considered an unusual condition. A refund would be provided only if no rocky conditions are encountered.

Staff does not disagree with the Company's policy with respect to charging customers for unusual conditions. However, Staff recommends that the definition be revised as follows to clarify that policy and avoid customer confusion:

> <u>Unusual Conditions</u> are construction conditions not normally encountered, but which *the Company may encounter during construction which impose additional, project-specific costs.* These conditions may include, but are not limited to: frost, landscape replacement, road compaction, pavement replacement,

> chip-sealing, rock digging/trenching, boring, non-standard facilities or construction practices, and other than available voltage requirements. *Costs associated with unusual conditions are separately stated and are subject to refund.*

Another issue raised by customers is delayed payment of refunds by the Company when the anticipated unusual conditions are not encountered. There is no provision in the existing or proposed Rule H tariff identifying the time frame for providing refunds. Staff proposes that a statement be added to Subsection 6.h., Unusual Conditions Charge, of Rule H to specify that if unusual conditions are not encountered, the Company will issue the appropriate refund within 30 days of completion of the project.

Elimination of Line Installation Agreements

Idaho Power proposes elimination of existing language describing Line Installation Agreements for Line Installation Allowances paid in excess $75,000. The Company does not believe such agreements are necessary. Staff does not object to the Company's proposal to remove the existing language.

Relocations in Public Road Rights-of-Way

The Company proposes to add a new section to address funding of roadway relocations required under *Idaho Code* § 62-705. This section identifies when and to what extent the Company will fund roadway relocations. Specifically, the section outlines Road Improvements for General Public Benefit, Roadway Improvements for Third-Part Beneficiary and Road Improvements for Joint Benefit.

Staff concurs with Idaho Power that clarification of the existing Rule H language is needed to address third-party requests affecting utility facilities in public rights-of-way. In keeping with the goal of having new growth pay its fair share of costs, and to insure consistency and fairness, Staff believes that inappropriate cost shifting from developers to Idaho Power customers should be prevented whenever possible. Staff supports the tariff language proposed by Idaho Power, but recognizes that its effectiveness will be tested over time and that additional modifications to the language may be required in the future.

Annual Updates to Charges and Allowances

With regard to annual updates to allowances, Staff supports annual updates if the allowances as proposed by Idaho Power are accepted by the Commission (*i.e.*, specific dollar amounts for customers in each class). However, if the Commission accepts Staff's proposed allowances (or allowances described as the cost of terminal facilities), then annual updates to the tariff are not necessary in the case of allowances because the cost of terminal facilities will automatically change as costs of transformers, meters and services increase. However, Staff does recommend that a set of "standard" terminal facilities costs be submitted annually to the Commission for informational purposes to permit Staff to track changes in costs.

Press Release and Letter to Builders

The Notice to Builders and Press Release were included in Idaho Power's Application received on October 30, 2008. Notice was direct mailed to the 400 builders and developers in the Company's service territory. Staff reviewed the Notice to Builders and Press Release and determined they were in compliance with the requirements of IDAPA 31.21.02.102.

RECOMMENDATIONS

Staff believes that the cost of new terminal facilities and line extensions needed to serve new customers should be paid by the customers who cause those costs to be incurred. Staff proposes that Idaho Power reduce its share of the investment in new distribution and terminal facilities to recover actual customer connection costs not currently recovered through rates, thereby relieving the upward pressure on rates that is caused by allowances and refunds included in the current line extension policy. Staff recommends that the Company's investment in facilities for each new customer be equal to the embedded costs of the same facilities used to calculate rates, and that costs in excess of embedded costs be borne by the customers requesting service through a one-time capital contribution.

Staff calculates that an investment of $1,232 would be revenue neutral for the residential customer class (Schedule 1) based on average annual consumption. Because this amount is nearly equal to the cost of terminal facilities for a typical residential customer, Staff recommends free overhead terminal facilities be provided by the Company for residential customers, and that no allowance be offered toward line extension costs.

For subdivisions, Staff recommends that refunds be made to subdividers as new customers are connected, in an amount equal to each lot's share of the transformer costs for the subdivision. Each residence in the subdivision would receive a free service cable and meter.

For small commercial customers (Schedule 7), average per customer revenues cannot support the full cost of terminal facilities. Consequently, Staff recommends an allowance equal to 60 percent of the cost of terminal facilities for single phase overhead service and 25 percent of the cost of overhead terminal facilities for three phase service.

For both the large commercial and the irrigation customer classes (Schedules 9 and 24), the embedded investment that can be covered through rates is sufficient to cover the expected terminal facilities cost for both single and three phase service. Staff recommends allowances equal to the cost of terminal facilities for these classes, but recommends that no additional allowance amount be offered toward line extension costs.

Staff performed an initial investigation to determine whether the line extension contributions collected from customers matched the actual costs incurred by the Company. Based on the information provided by Idaho Power, Staff has concerns about the number of work orders in which estimated costs varied substantially from actual costs, and the absence of a process to reconcile these costs with the customer. Staff recommends that a more thorough audit be conducted to better determine the extent of this problem and to pursue possible solutions.

Staff recommends the timing problem associated with the general overhead rate be corrected in the next rate case.

Staff does not believe Idaho Power has made a convincing case for reducing the vested interest refund period from five years to four years; consequently, Staff recommends that the refund period remain at five years.

Staff recommends approval of the Company's proposal to update engineering charges, overhead and underground temporary service attachment charges, and overhead and underground temporary service return trip charges. Staff also recommends approval of the Company's proposed tariff formatting changes and definition changes, and agrees with the Company's request to eliminate the requirement for line installation agreements. However, Staff recommends clarifying language for the definition of "unusual conditions."

Staff supports Idaho Power's proposal to add a new section to Rule H to address funding of roadway relocations. Staff supports the tariff language proposed by Idaho Power, but recognizes that its effectiveness will be tested over time and that additional modifications to the language may be required in the future.

Idaho Power has requested an effective date 120 days after receiving an order approving modifications to Rule H in order to update and test computer systems, train employees, and update internal documents related to administration of Rule H. Staff supports this request even though the effective date will likely be during the height of the annual construction season. Due to the downturn in the economy, there is very little new construction going on in Idaho Power's service territory. Consequently, any inconvenience to builders and developers is likely to be minor.

Respectfully submitted this 17TH day of April 2009.

Kristine A. Sasser

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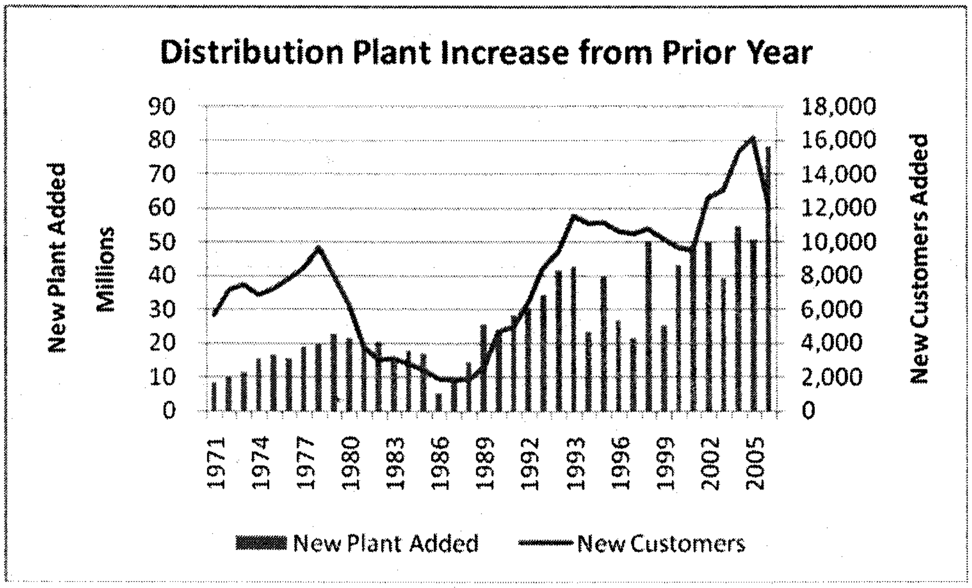
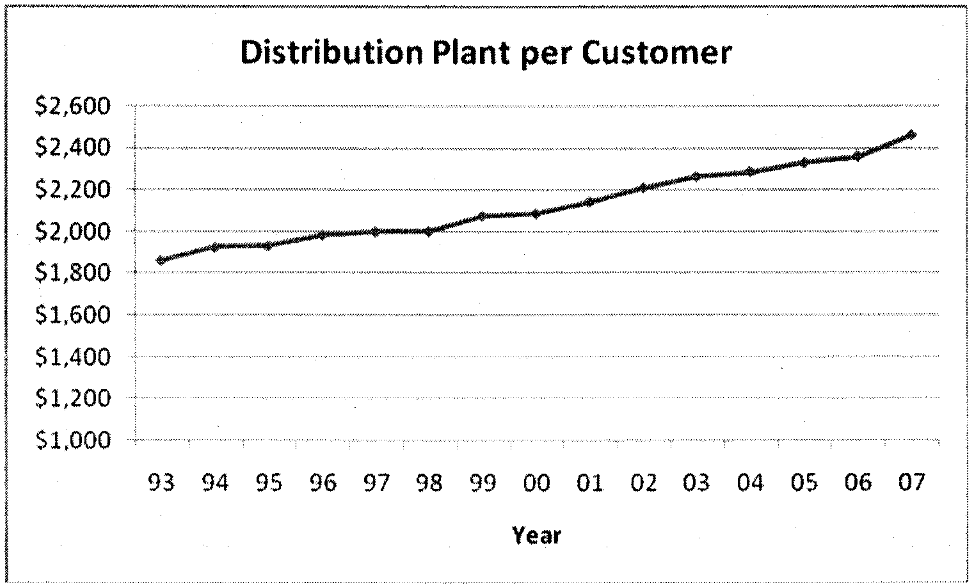
The Effects of Growth and Inflation on Electric Rates

Idaho Power's investment in distribution plant varies each year from less than $10 million to nearly $80 million. Distribution plant is a significant part of the Company's annual requirement for new investment dollars. Not surprisingly, the investment in distribution plant has generally increased through time, particularly since the mid-80s as shown in the graph below. New distribution plant investment over time has generally followed a similar pattern to the addition of new customers over time. Logically, as more new customers have been added, more new distribution plant has been added to serve them.



Not all new distribution plant that is added is for the purpose of serving new customers. Clearly, meters are periodically replaced, transformers fail, poles must be replaced or relocated, and other distribution plant must be added or replaced in order to continue to provide service to existing customers. Although Idaho Power does not track whether new distribution plant is added for the purpose of serving new customers or to continue to serve existing customers, the strong apparent correlation shown in the above graph between the addition of new plant and the addition of new customers would indicate that most new plant is added to serve new customers.

On a per customer basis, Idaho Power's investment in distribution plant has also increased over time. The graph below illustrates the Company's investment on a per customer basis from 1993 to 2007. A similar pattern existed before 1993. It is important to note that these figures <u>do</u> <u>not</u> reflect the actual cost of distribution facilities, but rather the Company's investment in those facilities. The level of Company investment in distribution facilities has been heavily influenced by changes in line extension policies over the years, as will be further discussed in more detail later.



Staff believes that the primary cause of the upward pressure on rates is adding new customers at higher levels of investment per customer than current rates can support. The combined effects of inflation on facilities costs, the rate of new customer growth and changes in line extension policies over time have all been factors. Staff also believes that changes in construction standards and a trend toward more underground installations have also contributed.

All of these factors affecting the investment required to connect new customers cause rates to increase. Each new customer that is added requires an investment in distribution plant and terminal facilities. The new investment is undepreciated, while the investment upon which the Company's revenue requirement (and rates) is calculated was both lower on a per customer basis when originally made and is now partially depreciated. Therefore, when the new plant investment is booked by the Company, the resulting revenue requirement is higher per customer than it was before the new customers were connected. The Company then has two alternatives: increase rates to all customers to cover the increased revenue requirement, or decrease the revenue requirement by shifting more of the investment in new distribution/terminal facilities to the customer for whose benefit those facilities are built. Staff believes it is more appropriate to shift more of the costs to new customers.

Attachment 1A shows two simple examples to illustrate the effects of customer growth and inflation on a utility's revenue requirement per customer — one assumes no inflation and the other assumes a 10 percent annual rate of inflation. When no inflation is assumed, the annual revenue requirement per customer declines each year because rate base decreases as more plant is depreciated. If only one customer were present on the system, the annual revenue requirement — at least the portion represented by depreciation and return on rate base — would decline to zero after four years. In this example, with the addition of a new customer each year and replacement of plant after it becomes fully depreciated, the annual revenue requirement per customer eventually becomes constant. The effect of growth is to cause the annual revenue requirement per customer to decline less rapidly than it otherwise would with no growth. If actual numbers for Idaho Power were used instead of simplified hypothetical ones, the effect of growth is the same, although much less pronounced because of approximately 30-year depreciation lives and growth rates of less than about five percent.

In the second example, when a 10 percent annual inflation is assumed, the effects on annual revenue requirement are greatly magnified. Based on the hypothetical numbers in this example, the annual revenue requirement per customer clearly increases at a faster rate each year. The graph at the bottom of Attachment 1A shows the difference in revenue requirement per customer with and without inflation.

Again, in reality, the results for Idaho Power are similar, although much less pronounced but on a much larger scale. It may also be worth noting from this example that with inflation but no growth, the annual revenue requirement per customer increases at the same rate of inflation, but in a sort of stair step fashion. When averaged over several years, inflation compounds the effects of growth.

Both growth and inflation are causes of higher annual revenue requirement per customer, but it is not critical to determine how much of the cause is attributable to growth and how much is attributable to inflation. In fact, even if much of the upward pressure on rates is caused by inflation, most of the additions to distribution plant are made to serve new customers, not old; therefore, the new customers should be responsible for the inflationary effects. If not for new customers, the amount of new distribution plant subject to inflationary pressure would be far less. To the extent new distribution investment is for replacement of existing facilities, all customers are responsible for inflationary effects.

Staff's proposal in this case does not remove the impact of past inflation from existing customers. They, along with new customers, are subject to the effects of inflation through eventual replacement of their facilities. These effects are eventually felt through general rate increases, since no customer is billed directly for replacement of facilities. Furthermore, under Rule H as currently structured, new customers pay only the increment above embedded cost through line extension fees, and in effect, pay the remainder of the cost through rates equal to what all other customers pay.

Besides new customer growth and inflation, Idaho Power's distribution investment per customer has also changed as a result of policy changes. Over the past 35 years the line extension policy for Idaho Power has changed many times, and there does not appear to have been any consistent basis for these policies. In fact, it appears that the level of Company investment in the past has been set depending upon how promotional the Company wanted to be in attracting new customers, depending upon economic conditions at the time or upon other factors. For example, in 1937 for residential customers, the Company limited its investment to three times the customer's guaranteed annual minimum billing. Between 1939 and 1945, the Company increased its investment limit to four and one-half times annual revenue. In 1945, the Company financed the entire cost of serving new customers. In 1948, the investment limit was 10 times annual revenue for residential and farm customers and five times revenue for commercial and industrial customers. Since 1955, the investment limit has continued to decline, until presently when the investment limit is approximately three times annual revenue for residential customers. With these facts in mind, it is apparent that the level of embedded Company investment per customer has been influenced as much or more by the line extension policy in effect at the time, as by inflation, rate of customer growth, construction standards or other factors.

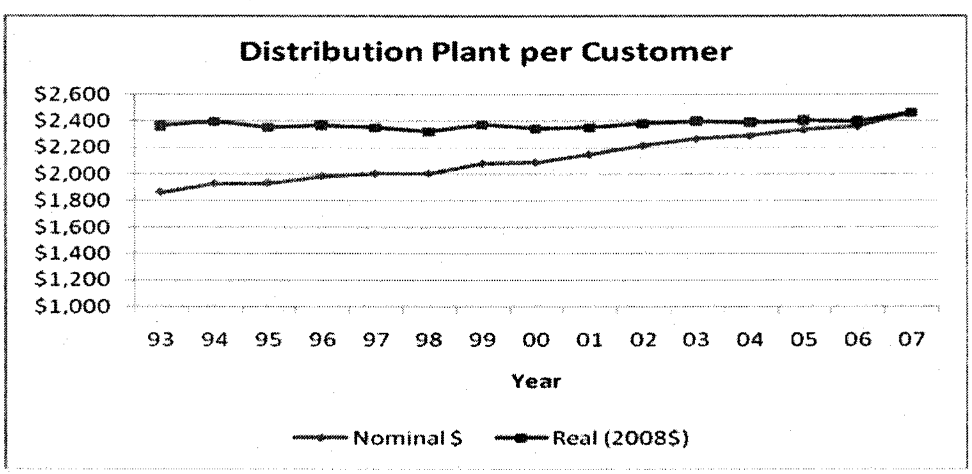
Staff's line extension proposal in this case is based on the calculated embedded costs for existing customers, which are used to calculate rates. This is exactly the same approach as was taken in Idaho Power's last major line extension case in 1995. Staff believes this is a more appropriate method than policies in effect prior to that time.

Despite just completing a recent rate case in which rates were increased, the Company's current rates are insufficient to cover all of the current average investment per new customer for required distribution plant and terminal facilities common to each new customer. Rates as set in

Idaho Power's recently completed general rate case were established based upon the average embedded investment per existing customer and are not sufficient to cover all of the current average investment per new customer. Rates will, however, support a significant portion of the required distribution/terminal facilities investment common to each new customer. If the Company continues to add new customers at costs higher than the average rate base used to calculate rates, upward pressure on rates will continue. Eventually another rate increase will be necessary. A rate increase may temporarily relieve the revenue deficiency problem caused by new customer investment, but it will not eliminate the upward pressure on rates.

Staff believes that the Company's investment in facilities for each new customer should be equal to the embedded costs of the same facilities used to calculate rates. Costs in excess of embedded costs should be paid through one-time capital contributions by the new customers. Staff further believes that those costs over and above the costs for standard overhead service with pole-mounted transformers and overhead distribution lines should be paid entirely by the customer requesting the new facilities.

By using the approach outlined here, Staff believes that the combined effect of new customers and inflation has been minimized, at least for distribution plant. The graph below shows the Company's distribution plant investment per customer both in nominal and real terms (2008$). As discussed previously, distribution plant investment per customer has increased steadily over time in nominal terms, but in real terms (when the effects of inflation are removed) distribution plant investment per customer has been very stable. Staff believes this is a good indication that the approach used to establish the current allowances is sound, and that it should continue to be used in the future.



Based on its analysis, Staff believes that adding new customers at higher required levels of investment needed to serve them puts upward pressure on rates. Staff agrees with Idaho Power that absent ongoing rate increases for all customers, the level of Company investment in new distribution facilities must be reduced in order to relieve upward pressure on rates.

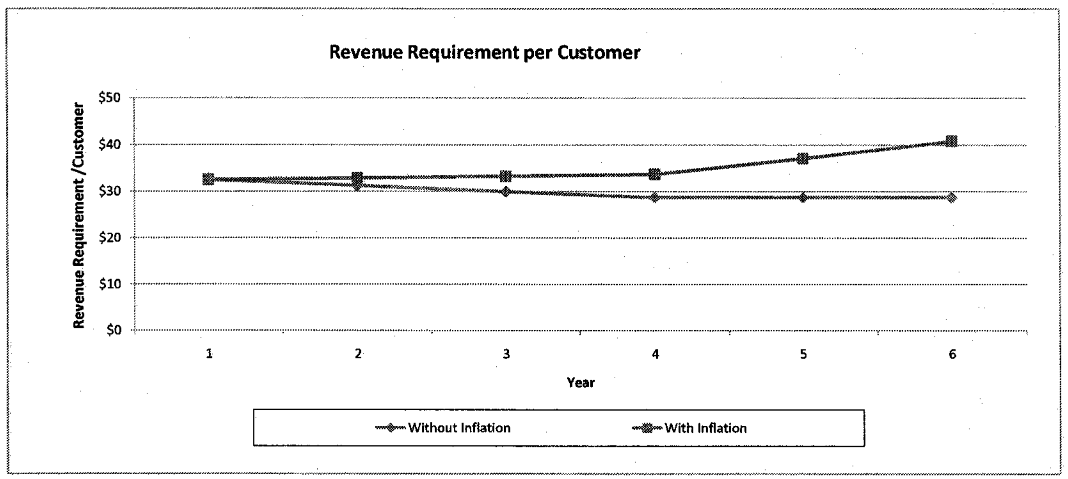
Cost of Growth Example
Without Inflation

Year ->	1				2				3				4				5				6			
	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return
Customer 1	100	25	75	7.5		25	50	5		25	25	2.5		25	0	0	100	25	75	7.5		25	50	5
Customer 2					100	25	75	7.5		25	50	5		25	25	2.5		25	0	0	100	25	75	7.5
Customer 3									100	25	75	7.5		25	50	5		25	25	2.5		25	0	0
Customer 4													100	25	75	7.5		25	50	5		25	25	2.5
Total	100	25	75	7.5	100	50	125	12.5	100	75	150	15	100	100	150	15	100	100	150	15	100	100	150	15
Revenue Requirement		32.5				62.5				90				115				115				115		
Revenue Reqmnt per Cust.		32.5				31.25				30				28.75				28.75				28.75		

Cost of Growth Example
With 10% Inflation

Year ->	1				2				3				4				5				6			
	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return	Invest.	Depr.	Rate Base	Return
Customer 1	100	25	75	7.5		25	50	5		25	25	2.5		25	0	0	146.41	36.60	109.81	10.98		36.60	73.21	7.32
Customer 2					110	27.5	82.5	8.25		27.5	55	5.5		27.5	27.5	2.75		27.5	0	0	161.05	40.26	120.79	12.08
Customer 3									121	30.25	90.75	9.08		30.25	60.5	6.05		30.25	30.25	3.03		30.25	0	0
Customer 4													133.1	33.28	99.83	9.98		33.28	66.55	6.66		33.28	33.28	3.33
Total	100	25	75	7.5	110	52.5	132.5	13.25	121	82.75	170.75	17.075	133.1	116.03	187.83	18.78	146.41	127.63	206.61	20.66	161.05	140.39	227.27	22.73
Revenue Requirement		32.5				65.75				99.83				134.81				148.29				163.12		
Revenue Reqmnt per Cust.		32.5				32.88				33.28				33.70				37.07				40.78		

Assumptions:
- Depreciation is booked beginning in year investment is made.
- Four year depreciation life.
- Investment for first customer is $100.
- One customer added each year
- 10% Rate of return.
- Annual revenue requirement = annual depreciation + return on rate base



Attachment 1A
Staff Comments
Case No. IPC-E-08-22
04/17/09

Net Plant and Allowable Investment by Customer Class

RESIDENTIAL (SCHEDULE 1)			
	Distribution	Terminal Facilities	Total
Net Plant per Customer*	$677	$427	$1,104
Allowable Investment per Customer	$750	$482	$1,232
SMALL GENERAL SERVICE (SCHEDULE 7)			
	Distribution	Terminal Facilities	Total
Net Plant per Customer*	$445	$415	$860
Allowable Investment per Customer	$498	$499	$997
LARGE GENERAL SERVICE (SCHEDULE 9)			
	Distribution	Terminal Facilities	Total
Net Plant per kW*	$125	$64	$189
Allowable Investment per kW	$136	$74	$210
IRRIGATION (SCHEDULE 24)			
	Distribution	Terminal Facilities	Total
Net Plant per kW*	$105	$58	$163
Allowable Investment per kW	$114	$64	$178
LARGE POWER (SCHEDULE 19)			
	Distribution	Terminal Facilities	Total
Net Plant per kW*	$100	$11	$111
Allowable Investment per kW	$109	$12	$122

* Net plant figures are from the cost of service study accepted by the Commission in IPC-E-08-10.

Assumptions Used in Calculating Allowable Investments

Cost of Capital			
Capital Component	Capital Structure	Component Cost	Weighted Cost
Long Term Debt	50.730%	5.927%	3.007%
Preferred Equity	0.000%	0.000%	0.000%
Common Equity	49.270%	10.500%	5.173%
Total	100.000%		8.180%

Grossed-up Rate of Return		
Tax Gross-up Factor		1.642
Weighted ROE * Tax Gross-up	5.173 * 1.642	8.495%
Long Term Debt		3.007%
Preferred Equity		0.000%
Grossed-up Rate of Return		11.501%

Depreciation Rates	Distribution Plant	Terminal Facilities	Composite Rate
	2.49%	2.45%	2.47%

Source for Cost of Capital is Order No. 30722, Case No. IPC-E-08-10

Summary of Cost of Service Figures

Residential (Schedule 1)

Number of Connected kW = 1,399,028
Number of Customers = 391,525
Avg kW per Customer = 3.573

	Plant in Service	Depreciation Reserve	Amortization Reserve	Net Plant	Customer Adv Constr	Accum Def Inc Taxes	Acquisition Adjustment	Working Capital	Plant Held for Future Use	Total Rate Base
Substations	86,970,563	20,770,153	411,984	65,788,426	0	3,875,802	(5,631)	1,200,217	385,093	63,492,304
Primary Lines	254,404,703	97,745,970	1,205,128	155,453,605	7,842,289	12,700,636	(16,472)	3,510,853	48,836	138,453,898
Secondary Lines	65,099,191	20,889,072	308,378	43,901,741	3,756,418	3,249,944	(4,215)	898,386	12,496	37,802,047
Subtotals	406,474,458	139,405,195	1,925,490	265,143,772	11,598,706	19,826,382	(26,318)	5,609,457	446,425	239,748,248
Transformers	201,296,968	77,093,064	953,554	123,250,351	92	10,049,340	(13,033)	2,777,952	38,641	116,004,478
Services	48,116,184	26,805,010	227,929	21,083,244	5,476,461	2,402,102	(3,115)	664,016	9,236	13,874,819
Meters	28,665,485	5,717,089	135,790	22,812,605	411	1,431,066	(1,856)	395,591	5,503	21,780,366
Subtotals	278,078,636	109,615,163	1,317,273	167,146,200	5,476,964	13,882,509	(18,005)	3,837,560	53,380	151,659,663
Totals	684,553,094	249,020,358	3,242,763	432,289,972	17,075,670	33,708,890	(44,322)	9,447,016	499,805	391,407,911
Total per Customer	1748.43	636.03	8.28	1104.12	43.61	86.10	-0.11	24.13	1.28	999.70

Small Commercial (Schedule 7)

Number of Connected kW = 50,204
Number of Customers = 31,171
Avg kW per Customer = 1.611

	Plant in Service	Depreciation Reserve	Amortization Reserve	Net Plant	Customer Adv Constr	Accum Def Inc Taxes	Acquisition Adjustment	Working Capital	Plant Held for Future Use	Total Rate Base
Substations	3,120,931	745,335	14,784	2,360,812	0	139,083	(202)	43,070	13,819	2,278,416
Primary Lines	14,923,318	5,733,755	70,693	9,118,871	460,027	745,016	(966)	205,946	2,865	8,121,672
Secondary Lines	3,553,836	1,140,357	16,835	2,396,644	205,067	177,418	(230)	49,044	682	2,063,655
Subtotals	21,598,086	7,619,448	102,311	13,876,327	665,094	1,061,517	(1,398)	298,059	17,366	12,463,743
Transformers	11,578,564	4,434,379	54,848	7,089,337	5	578,036	(750)	159,787	2,223	6,672,556
Services	4,189,520	2,333,937	19,846	1,835,737	476,840	209,153	(271)	57,816	804	1,208,093
Meters	5,040,214	1,005,228	23,876	4,011,110	72	251,622	(326)	69,556	968	3,829,613
Subtotals	20,808,298	7,773,544	98,570	12,936,185	476,918	1,038,812	(1,347)	287,160	3,994	11,710,262
Totals	42,406,384	15,392,991	200,881	26,812,512	1,142,012	2,100,329	(2,746)	585,219	21,360	24,174,005
Total per kW	844.68	306.61	4.00	534.07	22.75	41.84	-0.05	11.66	0.43	481.52

Summary of Cost of Service Figures

Large Commercial (Schedule 9)

Number of Connected kW = 820,387
Number of Customers = 26,848
Avg kW per Customer = 30.557

	Plant in Service	Depreciation Reserve	Amortization Reserve	Net Plant	Customer Adv Constr	Accum Def Inc Taxes	Acquisition Adjustment	Working Capital	Plant Held for Future Use	Total Rate Base
Substations	50,999,351	12,179,573	241,587	38,578,191	0	2,272,762	(3,302)	703,805	225,818	37,231,750
Primary Lines	80,571,984	30,956,923	381,674	49,233,387	2,483,715	4,022,392	(5,217)	1,111,915	15,467	43,849,445
Secondary Lines	21,643,077	6,944,845	102,524	14,595,707	1,248,870	1,080,486	(1,401)	298,680	4,155	12,567,784
Subtotals	153,214,411	50,081,340	725,784	102,407,286	3,732,585	7,375,640	(9,920)	2,114,400	245,439	93,648,980
Transformers	61,723,063	23,638,806	292,385	37,791,871	28	3,081,398	(3,996)	851,795	11,848	35,570,092
Services	4,169,976	2,323,049	19,753	1,827,173	474,616	208,178	(270)	57,547	800	1,202,457
Meters	16,517,498	3,294,276	78,244	13,144,978	237	824,602	(1,069)	227,946	3,171	12,550,185
Subtotals	82,410,536	29,256,130	390,383	52,764,022	474,881	4,114,178	(5,336)	1,137,287	15,820	49,322,734
Totals	235,624,947	79,337,471	1,116,167	155,171,308	4,207,466	11,489,818	(15,256)	3,251,687	261,259	142,971,714
Total per kW	287.21	96.71	1.36	189.14	5.13	14.01	-0.02	3.96	0.32	174.27

Irrigation (Schedule 24)

Number of Connected kW = 711,497
Number of Customers = 15,484
Avg kW per Customer = 45.950

	Plant in Service	Depreciation Reserve	Amortization Reserve	Net Plant	Customer Adv Constr	Accum Def Inc Taxes	Acquisition Adjustment	Working Capital	Plant Held for Future Use	Total Rate Base
Substations	44,230,205	10,562,978	209,521	33,457,706	0	1,971,098	(2,864)	610,389	195,845	32,289,978
Primary Lines	67,237,881	25,833,767	318,509	41,085,604	2,072,677	3,356,714	(4,353)	927,901	12,907	36,592,667
Secondary Lines	0	0	0	0	0	0	0	0	0	0
Subtotals	111,468,085	36,396,745	528,030	74,543,310	2,072,677	5,327,812	(7,217)	1,538,289	208,752	68,882,645
Transformers	55,662,916	21,317,881	263,678	34,081,357	26	2,778,858	(3,604)	768,163	10,685	32,077,719
Services	2,439,240	1,358,875	11,555	1,068,811	277,628	121,774	(158)	33,662	468	703,381
Meters	7,574,072	1,510,585	35,879	6,027,608	109	378,120	(490)	104,524	1,454	5,754,867
Subtotals	65,676,229	24,187,340	311,112	41,177,777	277,762	3,278,752	(4,252)	906,350	12,607	38,535,967
Totals	177,144,314	60,584,085	839,142	115,721,087	2,350,440	8,606,564	(11,469)	2,444,639	221,359	107,418,613
Total per kW	248.97	85.15	1.18	162.64	3.30	12.10	-0.02	3.44	0.31	150.98

Summary of Allowable Investment Calculation for the Residential Class

Return on Common Equity (Grossed-up)	$1104.12 * (.05173 * 1.642)	= $94.36
Debt Service Costs	$1104.12 * 0.03007	= $33.20
Subtotal		= $127.56
Depreciation Expense		= $45.26
Total Revenue Requirement		= $172.25

Return on Allowable Investment	+ Annual Depreciation	= Total Revenue Requirement
Allowable Investment (Grossed-up ROR)	+ Allowable Investment x Composite Depreciation Rate	= Total Revenue Requirement
Allowable Investment (11.501%)	+ Allowable Investment (2.47%)	= $172.25
	Allowable Investment (0.13769)	= $172.25
	Allowable Investment	= $172.25 / 0.13971
	Allowable Investment	= $1232.44

Allowable Investment by Customer Class

Residential (Schedule 1)			
# Customers	391,525		
Rate of Return	11.501%		
2008 Cost of Service Study	Distribution Plant	Terminal Facilities	Total
Net Plant	265,143,772	167,146,200	432,289,972
Return on Net Plant	30,495,267	19,224,166	49,719,433
Depreciation Expense	10,598,812	7,121,780	17,720,592
Total	41,094,079	26,345,946	67,440,024
Per Customer Expenses	Distribution Plant	Terminal Facilities	Total
Net Plant	677.21	426.91	1104.12
Return on Net Plant	77.89	49.10	126.99
Depreciation Expense	27.07	18.19	45.26
Total	104.96	67.29	172.25
Allowable Investment	**$750**	**$482**	**$1,232**

Small General Service (Schedule 7)			
# Customers	31,171		
Rate of Return	11.501%		
2008 Cost of Service Study	Distribution Plant	Terminal Facilities	Total
Net Plant	13,876,327	12,936,185	26,812,512
Return on Net Plant	1,595,973	1,487,843	3,083,816
Depreciation Expense	576,577	681,443	1,258,020
Total	2,172,550	2,169,286	4,341,836
Per Customer Expenses	Distribution Plant	Terminal Facilities	Total
Net Plant	445.17	415.01	860.17
Return on Net Plant	51.20	47.73	98.93
Depreciation Expense	18.50	21.86	40.36
Total	69.70	69.59	139.29
Allowable Investment	**$498**	**$499**	**$997**

Allowable Investment by Customer Class

Large General Service (Schedule 9)			
# Connected kW	820,387		
Rate of Return	11.501%		
2008 Cost of Service Study	Distribution Plant	Terminal Facilities	Total
Net Plant	102,407,286	52,764,022	155,171,308
Return on Net Plant	11,778,280	6,068,605	17,846,885
Depreciation Expense	3,838,295	2,388,485	6,226,780
Total	15,616,575	8,457,091	24,073,665
Per kW Expenses	Distribution Plant	Terminal Facilities	Total
Net Plant	124.83	64.32	189.14
Return on Net Plant	14.36	7.40	21.75
Depreciation Expense	4.68	2.91	7.59
Total	19.04	10.31	29.34
Allowable Investment	**$136**	**$74**	**$210**

Irrigation (Schedule 24)			
# Connected kW	711,497		
Rate of Return	11.501%		
2008 Cost of Service Study	Distribution Plant	Terminal Facilities	Total
Net Plant	74,543,310	41,177,777	115,721,087
Return on Net Plant	8,573,530	4,736,024	13,309,554
Depreciation Expense	2,781,702	1,619,622	4,401,324
Total	11,355,232	6,355,646	17,710,879
Per kW Expenses	Distribution Plant	Terminal Facilities	Total
Net Plant	104.77	57.87	162.64
Return on Net Plant	12.05	6.66	18.71
Depreciation Expense	3.91	2.28	6.19
Total	15.96	8.93	24.89
Allowable Investment	**$114**	**$64**	**$178**

Staff's Estimates of the Cost of Terminal Facilities

RESIDENTIAL (SCHEDULE 1)

Transformer		Switch, Cutout & Misc. Hardware	Service		Meter	Total
Overhead	$899	$213	Overhead	$235	$97	$1,444
			Underground	$1,377		$2,586
Pad-Mounted	$1,127	$213	Underground	$958	$97	$2,395

COMMERCIAL, IRRIGATION AND INDUSTRIAL (SCHEDULES 7, 9, 24, AND 19)

Single Phase

Transformer		Switch, Cutout & Misc. Hardware	Service		Meter	Total
Overhead	$899	$213	Overhead	$235	$277	$1,624
			Underground	$1,377		$2,766
Pad-Mounted	$1,127	$213	Underground	$958	$277	$2,575

Three Phase

Transformer		Switch, Cutout & Misc. Hardware	Service		Meter	Total
Overhead	$40.2/kW $1,859	$832	Overhead	$654	$735	$4080 + $40.2/kW
			Underground	$1,607		$5033 + $40.2/kW
Pad-Mounted	$13.4/kW $7,149	$832	Underground	$1,193	$735	$9909 + $13.4/kW

Attachment 7
Staff Comments
Case No. IPC-E-08-22
04/17/09

Idaho Power Line Extension Allowances

		Existing Allowance	IPCo Proposal	Staff Proposal
Schedule 1				
	Subdivision	Terminal Facilities + $800	$1780 per transformer	Terminal Facilities
	Non-electric heat	Terminal Facilities + $1000	$1,780	Terminal Facilities
	All-electric	Terminal Facilities + $1300	$1,780	Terminal Facilities
Schedule 7				
	Single Phase	Terminal Facilities	$1,780	60% of Terminal Facilities
	Three Phase	80% of Terminal Facilities	$3,803	25% of Terminal Facilities
Schedule 9				
	Single Phase	$1,726	$1,780	Terminal Facilities
	Three Phase	80% of Terminal Facilities	$3,803	Terminal Facilities
Schedule 24				
	Single Phase	$1,726	$1,780	Terminal Facilities
	Three Phase	80% of Terminal Facilities	$3,803	Terminal Facilities
Schedule 19				
		Case-by-case	Case-by-case	Case-by-case

Comparison of Costs
Residential Example

Example is for a single phase, residential lot with a 100' underground extension from an underground system. No electric space or water heating

Current Rule H			
Design Number		37196	vs 2
Work Order Cost			$7,284
Unusual Conditions			$1,000
Subtotal			$8,284
Overhead Transformer			($922)
Less Allowance	OH Terminal Facilities + $1000		($1,922)
Net Payment			$6,362
Amount Subject to Refund			$6,362

IPCo Proposed Rule H			
Design Number		37196	vs 4
Work Order Cost			$7,284
Unusual Conditions			$1,000
Subtotal			$8,284
Less Allowance	OH Terminal Facilities		($1,780)
Net Payment			$6,504
Amount Subject to Refund			$6,504

Cost Difference $142

Staff Proposal			
Design Number		37196	vs 4
Work Order Cost			$7,284
Unusual Conditions			$1,000
Subtotal			$8,284
Less Allowance	OH Terminal Facilities		($1,780)
Net Payment			$6,504
Amount Subject to Refund			$6,504

Cost Difference $142

Comparison of Costs for Residential Subdivisions

with 1.5% General Overheads Assumed

	Subdivision No. 1	**Subdivision No. 2**	**Subdivision No. 3**	**Subdivision No. 4**	**Subdivision No. 5**
Design Number	**61114**	**67186**	**60197**	**24482**	**27729**
Year of Development	2007	2007	2007	2002	2002
Number of Lots	3	10	32	60	101
Current Rule H					
Total Design Cost	$10,572	$13,713	$50,432	$72,528	$144,771
Terminal Facilities Allowance	$3,478	$3,382	$11,496	$15,645	$25,322
Work Order Cost	$7,094	$10,331	$38,936	$56,883	$119,449
Work Order Cost per lot	$2,365	$1,033	$1,217	$948	$1,183
Amount Eligible for Refund	$2,400	$8,000	$25,600	$48,000	$80,800
Meter, Service	$0	$0	$0	$0	$0
Net Cost per lot	**$1,565**	**$233**	**$417**	**$148**	**$383**
Proposed Rule H					
Total Design Cost	$10,572	$15,116	$50,432	$72,528	$144,771
Terminal Facilities Allowance	$3,560	$1,780	$7,120	$8,900	$17,800
Work Order Cost	$7,012	$13,336	$43,312	$63,628	$126,971
Work Order Cost per lot	$2,337	$1,334	$1,354	$1,060	$1,257
Amount Eligible for Refund	$0	$0	$0	$0	$0
Meter, Service	$0	$0	$0	$0	$0
Net Cost per lot	**$2,337**	**$1,334**	**$1,354**	**$1,060**	**$1,257**
Cost Difference per Lot	**$773**	**$1,101**	**$937**	**$912**	**$874**
Staff Proposal					
Total Design Cost	$10,572	$15,116	$50,432	$72,528	$144,771
Terminal Facilities Allowance	$0	$0	$0	$0	$0
Work Order Cost	$10,572	$15,116	$50,432	$72,528	$144,771
Work Order Cost per lot	$3,524	$1,512	$1,576	$1,209	$1,433
Amount Eligible for Refund	$3,560	$1,780	$7,120	$8,900	$17,800
Meter, Service	$0	$0	$0	$0	$0
Net Cost per lot	**$2,337**	**$1,334**	**$1,354**	**$1,060**	**$1,257**
Cost Difference per Lot	**$773**	**$1,101**	**$937**	**$912**	**$874**

Comparison of Costs
Irrigation Example

Example is for an irrigation customer with 3-phase overhead service and a connected load of 150 hp pump.

Current Rule H			
Design Number		76428	vs1
Work Order Cost			$17,385
Less Allowance	OH 3-phase Terminal Facilities		($7,709)
Engineering Fees			$500
Net Payment			$10,176
Amount Subject to Refund	Line Extension Costs - Engineering Fees		$9,676

IPCo Proposed Rule H			
Design Number		76428	vs 2
Work Order Cost			$17,385
Less Allowance	Standard 3-phase Terminal Facilities		($3,803)
Engineering Fees			$500
Net Payment			$14,082
Amount Subject to Refund	Line Extension Costs - Engineering Fees		$13,582

Cost Difference $3,906

Staff Proposal			
Design Number		76428	vs 2
Work Order Cost			$17,385
Less Allowance	Actual 3-phase Terminal Facilities		($7,709)
Engineering Fees			$500
Net Payment			$10,176
Amount Subject to Refund	Line Extension Costs - Engineering Fees		$9,676

Cost Difference $0

Comparison of Costs
Commercial Example

Example is for a large commercial customer with 3-phase overhead service and a connected load of 125 kW

Current Rule H				
Design Number		53545	vs2	
Work Order Cost			$14,646	
Less Allowance	80% of OH Terminal Facilities		($5,656)	
Engineering Fees			$300	
Net Payment			$9,290	
Amount Subject to Refund	Line Extension Costs - Engineering Fees		$8,990	

IPCo Proposed Rule H				
Design Number		53545	vs 3	
Work Order Cost			$14,646	
Less Allowance	Standard 3-phase Terminal Facilities		($3,803)	
Engineering Fees			$300	
Net Payment			$11,143	Cost Difference $1,853
Amount Subject to Refund	Line Extension Costs - Engineering Fees		$10,843	

Staff Proposal				
Design Number		53545	vs 3	
Work Order Cost			$14,646	
Less Allowance	Actual OH 3-phase Terminal Facilities		($7,070)	
Engineering Fees			$300	
Net Payment			$7,876	Cost Difference ($1,414)
Amount Subject to Refund	Line Extension Costs - Engineering Fees		$7,576	

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 17TH DAY OF APRIL 2009, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-08-22, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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