Decision 07-07-019 July 12, 2007

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of San Diego Gas & Electric Company and Southern California Gas Company (E-3921) for: Adoption of Their Residential Electric and Gas Line Extension Allowance Methodologies and its Monthly Ownership Charge Methodology.	Application 05-09-019 (Filed September 14, 2005)
Application of Pacific Gas and Electric Company in Response to Resolution E-3921, Proposing Revisions to Line Extension Allowance and Related Matters. (U 39 M)	Application 05-10-016 (Filed October 13, 2005)
Application of Southern California Edison Company (U 338-E) Regarding Residential Line and Service Extension Allowances.	Application 05-10-019 (Filed October 14, 2005)

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OPINION ADDRESSING ELECTRIC AND GAS RESIDENTIAL LINE EXTENSION ALLOWANCE CALCULATION METHODOLOGY

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OPINION ADDRESSING ELECTRIC AND GAS RESIDENTIAL LINE EXTENSION ALLOWANCE CALCULATION METHODOLOGY

I. Summary

By this order, we refine the calculation of line extension allowances, and the cost of ownership (COO) charges applicable to refundable costs in excess of the line extension allowance, for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SCG).[1] The above utilities are required to file advice letters to implement the refinements within 120 days. The refinements are as follows:

- Electric net revenue shall be based on the average distribution revenue per residential customer calculated as the total residential distribution revenue divided by the total number of residential customers.
- If the cost of an electric distribution rate discount is not included in residential electric distribution rates, but recovered separately from residential customers through a surcharge, the revenue effect of the discount shall be excluded from the calculation of average distribution revenue per residential customer.
- The results of the most recent California Residential Appliance Saturation Survey (RASS), implemented at the direction of the

[1] As used herein, the term "line extensions" is used to denote both line and service extensions. A line extension is an extension of the distribution line. A service extension connects the distribution line to the meter. When a new residential dwelling is constructed, a service extension will be necessary to provide utility service. A line extension may also be necessary if the existing distribution line is not close enough to allow a service extension to be connected. The allowance is applied to the service extension first. Any remaining allowance is applied to the line extension.

California Energy Commission (CEC), shall be used to determine average household appliance usage for each type of gas use.

- The average residential gas distribution rate shall be calculated as total residential distribution revenues divided by total residential usage.
- If the cost of a residential gas distribution rate discount is not included in residential gas distribution rates, but recovered separately from residential customers through a surcharge, the revenue reduction due to the discount shall be excluded from the average residential gas distribution rate calculation.
- Replacement for 60 years shall be included in the calculation of the cost of service (COS) factor.
- The types of data used to calculate the allowances shall include data that have been previously adopted by the Commission or derived from such data, recorded data, or data adopted by other state or federal agencies.
- The calculation of the COO charge applicable to refundable costs in excess of the line extension allowance shall include facility replacement for 60 years, and shall not include capital-related costs.

These applications are closed.

Due to the large number of acronyms used in this decision, a list of acronyms is included as Attachment A.

II. Procedural Background

On December 15, 2004, SCE filed Advice Letter SCE 1847-E. On December 20, 2004, SDG&E filed Advice Letters 1647-E for its electric operations and Advice letter 1494-G for its gas operations. These advice letters sought to revise residential line extension allowances. Resolution E-3921, dated June 16, 2005, which addressed these advice letters, ordered SCE, SDG&E, SCG, and PG&E to file applications addressing policy and methodologies for determining line extension allowances and monthly cost of ownership charges. The applications that are the subject of this proceeding were filed in response to Resolution E-3921.

Prehearing conferences were held on February 7, 2006 and March 23, 2006. An assigned Commissioner's ruling and scoping memo was issued on April 4, 2006, which confirmed the preliminary determinations that the category of the proceedings is ratesetting and that hearings were needed. Hearings were held from September 18-21, 2006. This proceeding was submitted on October 30, 2006.

The issues relating to residential line extensions to be addressed in this proceeding are as follows:

- Calculation of the net revenue on which line extension allowances are based.
- Whether the Cost of Service factor should account for replacement in perpetuity.
- Sources of data for calculating line extension allowances.
- Whether line extension allowances should continue to be offered in portions of the utilities' service territories where publicly-owned energy utilities (POUs) are offering service.
- Criteria for requiring a revenue impact estimate to be included in a line extension allowance change advice letter.
- Cost components to be recovered by the monthly COO charge.
- The relationship of the monthly COO charge to monthly charges for operations and maintenance of special distribution facilities, and the COS factor.

- For SCE only, whether sub-transmission costs should be considered distribution costs for the purpose of calculating line extension allowances.

III. Line Extension Allowance Background

When a residential dwelling is constructed, the entity that owns the dwelling (applicant) will have to apply to the electric and/or gas utility to be connected to the utility's system.[2] The facilities that will have to be built to make the connection are of two kinds. First, the utility's distribution line will have to be extended to the edge of the applicant's property if not already there. This is called a line extension. Second, the utility's distribution line will have to be connected to the dwelling's meter. This is called a service extension. As used herein, the term "line extension" refers to both the line and service extension.

The cost of a residential line extension is divided into two parts: non-refundable and refundable. The non-refundable costs are paid for by the applicant. The refundable costs are covered in whole or in part by the line extension allowance. The allowance is a fixed amount for each utility. For example, PG&E's line extension allowance for electric service is currently $1,313. The refundable costs (electric wire, etc.), in excess of the allowance, are advanced by the applicant to the utility. Refunds are paid to the applicant due to additional services subsequently connected to the line extension and/or line extensions subsequently connected to the applicant's line extension, and continue for up to 10 years from the date the utility is first ready to serve.[3] In

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[2] The term "applicant," as used herein, refers to the applicant for the line extension, rather than the utilities who filed the instant applications.

[3] Refunds are made on line extensions, not service extensions.

most cases, the applicant will be the developer who constructs the dwelling, not the customer who ultimately occupies the dwelling. It is the applicant who receives any refunds.

For gas service, the line extension allowance works the same way except that the amount of the allowance will vary depending on the types of gas usages in the dwelling. The four types of usage are space heating, water heating, cooking, and clothes drying. For example, PG&E's gas line extension allowances for the four types of usages are currently as follows:

- Space heating—$323
- Water heating—$310
- Cooking—$69
- Clothes drying—$60.

The total gas line extension allowance would be the sum of the allowances for each usage. In the above example, a dwelling with all four usages would have an allowance of $762.

The allowance goes into the utility's rate base. Costs in excess of the allowance are paid for by the applicant for the line extension. Excess refundable costs are subject to refund to the applicant over a 10-year period. Refunds are based on additional services subsequently connected to the line extension and/or line extensions subsequently connected to the applicant's line extension.[4] The utility is responsible for the operation, maintenance, and replacement of the line extension facilities. For any portion of the refundable amount that has not been

[4] Refunds are made on line extensions, not service extensions.

refunded to the applicant after 12 months for electric service or 36 months for gas service, the applicant is charged a monthly COO charge to recover the operations and maintenance (O&M) costs and other costs of the facilities.[5] After the 10-year period, any unrefunded amount becomes the utility's property.

In addition to the COO charge applicable to the unrefunded amount, there are COO charges that apply to special facilities.[6] These are addressed in Section X of this decision.

The electric line extension allowance is calculated using the following general formula**:**

$$\text{Allowance} = \frac{\text{Net Revenue}}{\text{COS factor}}$$

The net revenue is the annual revenue expected to be received by the utility from the customer residing in the dwelling. For electric service, the net revenue is calculated based on the utility's average annual distribution revenue per residential customer. For gas service, the net revenue is based on average annual residential usage for each type of appliance (space heating, water heating, cooking, and clothes drying) times the average residential distribution rate.

Associated with the cost of the line extension facilities that go into the utility's rate base are costs for such things as depreciation, return, income taxes, property taxes, O&M costs, administrative and general (A&G) costs, and franchise fees and uncollectibles (FF&U). The COS factor is the ratio of such

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[5] The COO charge does not apply to individual applicants, such as a person building his or her own home.

[6] Special facilities are facilities requested by the applicant that are in addition to, or in substitution for, standard facilities the utility would normally provide.

costs to the cost of the line extension. Thus, a COS factor of 0.16 means that for every $100 of line extension cost, $16 in revenues is needed to recover the associated costs. Using this hypothetical example, if the net revenue is $160 and the COS factor is 0.16, the allowance would be $1,000.

IV. Calculation of the Net Revenue on Which Line Extension Allowances are Based

A. Positions of Parties

The utilities generally support the existing methods of calculating net revenue. However, the Commission's Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN) and other parties have proposed changes to that calculation.

DRA

DRA states that the current calculation of net revenue is based on gross distribution revenue and, therefore, includes revenues needed to cover costs other than costs directly attributable to line extensions. DRA argues that existing customers subsidize new customers because use of gross distribution revenue as the basis for the line extension allowance calculation means that new customers will not pay for distribution costs that are not directly related to line extensions.

DRA bases its recommendations on the following language from Decision (D.) 97-12-098:

> "applicants should receive such free allowances only to the extent that the revenue expected to be received from the load to be served matches the utility's investment…ratepayers will not be overpaying in those allowances for revenues that will never materialize."

DRA states that this language leads to the following rules that lay the foundation for its recommendation:

1. Line extension allowances should be granted only for revenues which match the utility's investment; and

2. Existing ratepayers should not overpay for allowances when compensatory revenues do not materialize.

DRA proposes that only those revenues directly associated with line extensions should be included in net revenue. DRA recommends that the way to calculate the revenues that directly support line extensions is to subtract the following from average gross distribution revenues per customer:

1. Long-term customer marginal service costs: costs associated with meter reading, billing, and meter services.

2. Upstream distribution marginal costs: capital costs associated with facilities between the substation and those facilities within Rules 15 and 16 (line and service extensions).

3. Primary distribution marginal costs: capital costs associated with the broad distribution system.

DRA states that it used the above marginal costs instead of embedded costs because average gross distribution revenue per customer is just sufficient to recover each customer's allocation of embedded costs. Thus, the use of embedded costs would lead to a net revenue of zero.

DRA proposes that line extension allowances should be considered during general rate cases (GRCs) or Biennial Cost Allocation Proceedings (BCAPs) rather than advice letters, due to the greater complexity and controversial nature of its recommendations.

TURN

TURN proposes inclusion in net revenue of only those revenues that directly support line extensions. TURN argues that the way to calculate the revenues that directly support line extensions is to subtract the following from average gross distribution revenues per customer:

1. Marginal customer service costs: expenses associated with meter reading, billing, and the like.

2. Marginal demand costs: costs associated with facilities between the substation and the line and service extensions.

TURN states that its proposed removal of marginal customer costs and marginal demand costs from net revenues reflects embedded costs and does not change the net revenue calculation to a marginal cost methodology because TURN does not propose to remove the Equal Percentage Marginal Cost (EPMC) scalar.[7]

TURN opposes PG&E's request to include local gas transmission revenue in the net revenue calculation because these transmission lines do not directly serve new customers and the costs are not directly attributable to providing service to new customers.

TURN recommends the gas allowance for water and space heating be combined, and that no allowance for either use be given unless the customer uses gas for both purposes. TURN states that this would eliminate uneconomic single use gas extensions and the uneconomic substitution of electric space heat for gas space heat.

TURN recommends removal of downstream customer costs from gas net revenues for the same reasons that marginal customer service costs should be removed from electric net revenues. In addition, TURN recommends that

[7] The EPMC scalar is used to convert marginal costs to embedded costs.

downstream customer costs be removed from the gas allowance after all of the individual components are calculated rather than from any single end use because such costs are the same regardless of the number of end uses.

MID

The Modesto Irrigation District and the Merced Irrigation District (collectively MID) state that rate or line extension cost discounts lead to subsidization by other ratepayers. MID says that this is especially important when the revenue effects of discounts have not been taken into consideration in the net revenue calculation on which those discounts are based. Therefore, MID recommends that a customer-specific discount should be calculated for customers who will receive a rate or line extension cost discount to ensure that the discount is revenue justified.

MID states that PG&E has not shown that provision of allowances in areas served by POUs would result in a positive net contribution to margin that is necessary to justify such allowances.

MID states that utility shareholders should be required to share the cost of any ratepayer subsidy created by provision of allowances in areas served by POUs.

CBIA

The California Building Industry Association (CBIA) states that upstream distribution costs should not be deducted from net revenue or charged to new customers because such facilities serve other customers as well.

CBIA states that local gas transmission revenues should be included in net revenue because the utilities provide higher pressure gas services to distributed generation and cogeneration facilities. CBIA also states that public purpose program costs that benefit new customers should be included in net revenues.

PG&E

PG&E proposes to calculate average residential electric usage as total residential distribution revenue divided by the number of customers. PG&E states that this will better reflect electricity usage in its service territory. PG&E also proposes to retain its existing methodology for calculating gas net revenue.

PG&E proposes to include local gas transmission revenue in gas net revenues because they serve the same function as high pressure gas distribution lines. PG&E states that SDG&E and SCG (collectively Sempra) include revenues supporting high pressure distribution lines in net revenues.

PG&E states that DRA's and TURN's proposals to use marginal costs would understate the actual revenues contributed by new customers, inhibit PG&E's ability to attract new load (resulting in higher rates), and result in higher housing prices. PG&E also points out that some of the marginal cost information necessary to implement DRA's and TURN's recommendations is not readily available for PG&E and does not exist for SCE and SDG&E.

SCE

SCE recommends that it be allowed to continue using its current method of calculating net revenues except that it is willing to base net revenues on the residential revenues and number of customers adopted in its most recent GRC rather than basing it on its TOU-D-1 rate schedule.

SCE states that it excludes rate discounts from its net revenue calculation because the lost revenues due to discounts received by one group of customers are recovered from other customers. For example, it excludes the California Alternative Rates for Energy (CARE) discount and the CARE surcharge.

SCE states that DRA's proposal, which SCE characterizes as being based on a standard of ratepayer indifference, is inconsistent with the Commission's policy of basing net revenues on distribution revenues. SCE argues that if the Commission meant ratepayer indifference to be the standard, it would have included other revenues (generation and transmission) to evaluate the overall effect on ratepayers.

SCE states that basing the net revenue calculation on marginal costs would be difficult to implement because not all of the utilities have the data readily available and, due to the controversial nature of marginal costs, would be difficult to implement using a streamlined advice letter process.

Sempra

Sempra recommends continuation of its current calculation methodology for electricity and gas.

Sempra recommends that the average household gas usage be calculated based on a recent conditional demand analysis similar to one recently completed by the CEC using the 2003 RASS.

Sempra does not reflect discounts in its net revenue calculation (similar to SCE).

Sempra includes local gas high-pressure distribution revenues, but not transmission or storage revenues, in its net revenue calculations.

Sempra opposes DRA's proposed use of marginal costs in the net revenue calculation because it would be biased against new customers since all units of demand are marginal whether from new or existing customers.

Sempra states that upstream distribution costs (costs for facilities upstream of the line extension) should be excluded from costs associated with the line extension because such costs are common to and benefit all customers.

B. Electric Net Revenues—Current Status

Currently, the net revenue is calculated as the average residential distribution revenue per customer less revenue cycle service (RCS) credits.[8] The only difference between the utilities' net revenue calculation methodologies is how the average residential distribution revenue per customer is calculated.

In calculating electric net revenues, PG&E currently calculates average residential revenue as average household usage times the average residential distribution rate. The average household usage is taken from a usage survey by the United States Department of Energy (DOE) which provides average residential usage for California as a whole.

SDG&E currently calculates average electric distribution revenue per customer as the total distribution revenue divided by the number of customers.

SCE currently calculates average electric residential distribution revenue per customer using the distribution component of the TOU-D-1 rate schedule times average residential usage. SCE states that the TOU-D-1 rate schedule reflects the average residential distribution rate.

C. Discussion—Electric

Costs related to distribution facilities, including line extension allowances, are recovered only through distribution rates. Therefore, distribution revenues are the appropriate starting point for determining net revenue. Since the average distribution revenue per residential customer is the average amount of revenue that can be expected to be received from the average residential

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[8] Under direct access, revenue cycle services (metering, billing and related services) are not provided by the utility. Therefore, the direct access customer receives the RCS credit for the costs of those services.

customer, it is the amount available to pay for the allowance. Therefore, the net revenue cannot exceed the average distribution revenue per residential customer. The issue is then what should be subtracted from the average distribution revenue per residential customer to determine net revenues.

In D.94-12-026, the Commission defined net revenue as: "That portion of the total rate that supports the utility's extension costs and excludes such things as fuel costs and other energy adjustment costs that do not support the extension costs."[9] The Commission also determined that the allowances should be "revenue-based." That is, the allowances "would be based on the expected supporting revenues from the loads to be served by the extension."[10]

In D.97-12-098, the Commission determined that line extension allowances should be "revenue-justified." That is, allowances should be set such that the revenue expected to be received from the load to be served "matches" the utility's investment. The Commission also decided that the allowance should be distribution-based to reflect the unbundling of utility rates.

In the above referenced decisions, the Commission did not precisely define what it meant by revenues that "support" line extension costs or "match" the utility's investment. As a result, there is no precise definition of what net revenues should include. However, these decisions establish the Commission's overall policy that the allowance should be revenue justified based on distribution revenues expected to be received from the residents of new dwellings.

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[9] Appendix B, p. 14 (regarding gas mains) and p. 45 (regarding electric extensions).

[10] D.94-12-026, footnote 2.

DRA and TURN argue that new customers will never pay the cost of providing the allowance, much less all of the other costs of providing distribution service and, therefore, will be subsidized by existing customers. DRA's and TURN's references to "new customers" appear to refer to customers residing in new dwellings and/or developers. To eliminate this subsidy, DRA and TURN recommend calculating net revenues by subtracting from average distribution revenues per customer those costs not directly associated with line extensions.

The term "subsidy" is commonly defined as a grant of money by the government to an entity in support of an enterprise regarded as being in the public interest. In the case of line extensions, the line extension allowance is a subsidy of the applicant paid for by ratepayers. However, the mere existence of this subsidy does not mean it is disadvantageous to ratepayers. Therefore, a more appropriate question is whether there is an unreasonable subsidy.

In order for there to be an unreasonable subsidy, the costs of the allowance must exceed its benefits. The allowance is paid for by residential ratepayers. The record shows that the primary direct beneficiary of the allowance is the developer. The question is to what extent ratepayers receive a benefit.

Only two possible ratepayer benefits have been identified in the record. The first benefit would be a positive contribution to margin, on average, due to the addition of new dwellings.[11] The second benefit would be due to a reduction in housing prices (new dwellings and the housing market as a whole). It is not

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11 A positive contribution to margin occurs when revenues from the customer exceed the variable costs to serve the customer, thus providing recovery of some of the fixed costs.

reasonable to assume that provision of the allowance is the sole reason that a new dwelling will be built. Therefore, only some portion of the contribution to margin, if any, generated by the addition of a new dwelling would be due to the allowance. Nothing in the record demonstrates what the contribution to margin would be, much less how much of any positive contribution would be due to the allowance. That leaves the second possible benefit.

A possible benefit of the allowance to the owner of a new dwelling would be a reduction in the cost of the dwelling. If the dwelling is rented, the only direct benefit to the renter would be a reduction in the rent due to a reduction in the cost of the dwelling. It is reasonable to assume that the allowance reduces the total cost to construct a dwelling.[12] However, the record does not indicate that prices charged by developers for new dwellings are strictly cost-based. Thus, the record does not indicate what benefit the owner of a new dwelling will actually receive from the allowance. The record also does not indicate that the rent charged for a new dwelling will be strictly cost-based. Therefore, the record does not indicate what benefit the renter of a new dwelling will actually receive from the allowance. Likewise, the record does not demonstrate that the allowance will have a material effect on the overall price of housing. Thus, the record does not indicate what benefit customers residing in existing dwellings will receive. Overall, the record does not indicate whether there is a significant benefit to ratepayers due to a reduction in new and/or existing housing prices, much less what the value of any benefit would be.

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[12] The record demonstrates that the allowance comprises about 0.19% of the cost of a new dwelling costing $650,000.

As discussed above, the record is insufficient to determine what benefits ratepayers receive from the allowance. Thus, the ratepayer benefits of the allowance cannot be compared to the costs of providing the line extension allowances. In addition, the record does not address whether there are other unquantified benefits that would make the subsidy reasonable. Therefore, the record does not demonstrate that an unreasonable subsidy exists. The Commission's current formula was previously determined by the Commission to be reasonable. For the Commission to revise its formula, as recommended by DRA and TURN, we would have to determine that there is an unreasonable subsidy and that TURN's and/or DRA's recommendations would reduce or eliminate the unreasonableness of the subsidy. DRA and TURN have not demonstrated either that there is an unreasonable subsidy or that their recommended subtraction of specified costs from the net revenue calculation would rectify the situation. Thus, they have not demonstrated their recommendations to be more reasonable than the Commission's current methodology.

In D.98-09-070, the Commission directed PG&E, SCE, and SDG&E to propose changes to the line extension rules that remove revenues associated with unbundled revenue cycle services for direct access customers from the line extension allowance calculation. As a result, in D.99-12-046, the Commission removed the RCS credit from the electric line extension allowance calculation.

Direct access electric service is not currently available to new customers, but may be resumed at some point.[13] Therefore, the customer residing in a new dwelling may eventually take direct access service. Thus, future revenues from direct access customers may be reduced by the amount of the RCS credits. As discussed above, the Commission's policy is that the allowance should be revenue-justified. DRA and TURN recommend subtraction of marginal customer costs from average residential distribution revenues rather than RCS credits. However, the issue is the revenues that will be lost due to direct access, not the cost of providing revenue cycle services. RCS credits are appropriate for exclusion from the net revenue calculation because they represent the lost revenues. Thus, we do not adopt DRA's and TURN's recommendation to subtract the utility's marginal customer cost, rather than RCS credits. In addition, since we do not adopt DRA's and TURN's recommendations as discussed above, we need not limit allowance changes to GRCs and BCAPs.

The electric net revenue is calculated based on average residential distribution revenues per customer. The calculation should reflect factors, such as rate discounts, that may impact revenues because customers residing in new dwellings may receive such discounts. The use of total residential distribution revenues divided by the number of customers would reflect average revenue per customer including baseline usage, discounts, etc. Therefore, electric net revenue should be based on the average distribution revenue per residential customer

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[13] Direct access was suspended by D.01-09-060. The Alliance for Retail Energy Markets filed a petition for rulemaking (P.06-12-002) on December 6, 2006, which requests that the Commission consider a process for lifting the suspension of direct access.

calculated as the total residential distribution revenue divided by the total number of residential customers.

The cost of a residential distribution rate discount, such as the CARE discount, is usually recovered from residential customers through residential distribution rates or a surcharge. If the cost of a discount is not included in residential rates, but recovered separately from residential customers through a surcharge, the revenue effect of the discount on residential customers is not fully reflected in distribution rates. To make sure it is fully reflected in the net revenue calculation, if the cost of the discount is not recovered through the distribution rate, the revenue reduction due to the discount should be excluded from total distribution revenues.

MID recommends calculation of a customer-specific allowance for customers who will receive a rate or line extension cost discount to ensure that the discount is revenue justified. Most new dwellings are built by developers who are the recipients of the line extension allowances. The customer who will live there can not be identified until the dwelling is sold. Whether that customer will receive a rate discount will likely be unknown when the allowance is provided to the developer. In addition, subsequent residents of the dwelling may or may not receive a rate discount.

As to discounts applicable to residential line extensions, the record indicates that developers are eligible to receive from the utilities 50% of the line extension costs in excess of the allowance rather than refunds based on additional services or line extensions subsequently connected to the applicant’s line extension.[14] Whether this comprises a discount to the developer depends on whether additional services and/or line extensions are subsequently connected to the applicant's line extension, which will not be known at the time the allowance is calculated. For the above reasons, MID's proposal is not feasible and we do not adopt it.

D. Gas Net Revenues—Current Status

Gas line extension allowances are based on appliance usage in the residence. The four types of usage are space heating, water heating, cooking and clothes drying. The allowance for each residential dwelling is based on which of the four usages it will have. No equivalent of the electric RCS credits is subtracted.

PG&E calculates the net revenue as the average household usage in California for the particular end use times the average residential distribution rate. The average household usage in California is taken from a DOE residential energy consumption survey.

Sempra calculates the net revenue as the average household usage in their service territories for the particular end use times the average residential distribution rate. They currently calculate the average household usage using the results of a 1999 conditional demand analysis based on customer residential appliance usage.

E. Discussion—Gas

TURN recommends removal of downstream customer costs (costs associated with meter reading, billing and meter services) from gas net revenues.

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[14] This option is not within the scope of this proceeding.

This is essentially the same as TURN's recommendation that marginal customer service costs be removed from electric net revenues instead of RCS credits, and TURN's reasoning is essentially the same.

RCS costs were removed from electric net revenues due to the unbundling of revenue cycle services. Since revenue cycle services have not been unbundled for gas, no revenues will be lost. No gas equivalent of the RCS credit has been established for gas utilities as a whole and we have not required that such a credit be deducted from gas net revenues.[15] Therefore, we do not adopt TURN's recommendation.

The appliance usages used to determine the allowance should reflect the usages in each utility's service area, rather than aggregate California usage as used by PG&E. The RASS is implemented at the direction of the CEC to determine appliance saturation and usage for each of the participating utilities. Since PG&E and Sempra participate in the RASS, it should be used to determine average household usage for each type of use.

The average residential rate is multiplied by the appliance usages to determine the net revenue. The average residential rate should reflect factors, such as rate discounts, that may impact revenues because customers residing in new dwellings may receive such discounts. Thus, the rate should be calculated as total residential revenues divided by total residential usage.

The cost of a residential rate discount is usually recovered from residential customers through residential distribution rates or a surcharge. If the cost of a discount is not included in residential rates, but recovered separately from

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[15] An avoided cost credit was established for PG&E gas in D.00-05-049. However, no such credit has been established for Sempra.

residential customers through a surcharge, the revenue effect of the discount on residential customers is not fully reflected in distribution rates. To make sure such discounts are fully reflected in the net revenue calculation, if the cost of a discount is not included in residential rates, but recovered separately from residential customers through a surcharge, the discount should be excluded from the average rate calculation.

PG&E proposes to include local gas transmission revenue in gas net revenues because they serve the same function as high pressure gas distribution lines. Local gas transmission costs are not recovered in distribution rates. Therefore, inclusion of such revenues in the net revenue calculation would not be revenue justified. Thus, we do not adopt PG&E's proposal.

V. Whether the COS Factor Should Account for Replacement in Perpetuity

A. Positions of Parties

PG&E

PG&E states that the elements used to calculate the COS factor should be the same as those included in the net revenue calculation and, if the net revenues are calculated on a marginal cost basis, the COS factor should also be calculated on a marginal cost basis.

SCE

SCE argues against inclusion of replacement in perpetuity in the COS factor calculation because the net revenue calculation does not include replacement in perpetuity.

Sempra

Sempra recommends that the COS factor should include replacement in perpetuity. Sempra contends that its COS factor calculation does so through the inclusion of book depreciation.

Sempra states that, if the net revenue is changed as proposed by DRA and TURN, the COS factor must be changed accordingly.

DRA

DRA states that no changes to the COS factor will be necessary due to implementation of its recommendations regarding net revenues.

DRA argues that once a line extension is in place, the utility owns it and is responsible for its replacement. Therefore, if the COS factor does not assume replacement in perpetuity, the assumption is made that the customer will pay for the replacement, which is not the case. Thus, DRA recommends that replacement in perpetuity be assumed in the COS factor calculation.

TURN

TURN recommends that the COS factor should include a component for the cost of replacing line and service extension assets at any time during their expected useful lives because the utility is responsible for such replacement.

TURN argues that depreciation is not sufficient to cover replacement costs. TURN states that depreciation is intended to recover the original investment plus the cost of removal less the salvage value, does not account for inflation, and does not collect sufficient funds to pay for replacement due to failure before the end of the equipment's useful life.

TURN argues that net revenue includes costs for replacements in the GRC test years and, therefore, the argument that replacement costs should not be included in the COS factor because they are not in net revenues is incorrect.

CBIA

CBIA states that the COS factor should not include replacement in perpetuity because any replacements will go into ratebase and be recovered in rates.

B. Discussion

Once a line extension has been installed, its maintenance and replacement become the utility's responsibility. Therefore, we find it reasonable to require that replacement be included in the calculation of the COS factor. The overall life of line extension facilities is approximately 30 years, with the lives of some components being longer and some shorter. No party has suggested that the life of a residential dwelling is limited to the life of the line extension. Therefore, the utility will have to replace the line extension at the end of its useful life. No party has provided evidence as to how long a residential dwelling will last on average, but it is common knowledge that residential dwellings, although they will not last forever, can last well in excess of 60 years. As a result, for the purpose of calculating the COS factor, we will use 60 years as the period during which replacements will be performed.

As stated by TURN, the purpose of depreciation is to recover the original capital cost of facilities, adjusted for any salvage and/or removal costs, over their useful lives. It does not provide for replacement of the facilities at the end of their useful lives. Therefore, the inclusion of depreciation in the COS factor does not, as alleged by Sempra, provide for replacement in perpetuity.

Net revenue is based on average distribution revenue per residential customer. Portions of that revenue are then subtracted. Net revenue is intended to be those CPUC jurisdictional distribution revenues that will be paid to the utility and can be used to pay costs of the line extensions. Those revenues are based on current rates. The argument has been made that if the COS factor includes replacement in perpetuity, the net revenues would have to be adjusted. This argument is incorrect. Rates include costs for replacements of line extension facilities during the forecast period because they are the utility's responsibility.[16] Thus, the net revenue based on those rates includes replacements. Both PG&E and Sempra represent that their COS factor calculations include replacements. However, they do not adjust their net revenue calculations due to such inclusion. Thus, we see no reason to adjust net revenues due to our inclusion of replacement in the COS factor.

Since we do not adopt DRA's and TURN's recommendations for subtracting certain marginal costs from net revenues, we need not address whether adoption of their recommendations would necessitate a change in how the COS factor is calculated.

VI. Sources of Data for Calculating Line Extension Allowances

A. Positions of Parties

PG&E

[16] The forecast period in a GRC is the test year plus generally two attrition years.

PG&E proposes to use the same sources of data as was used in the past with one exception. For electric usage, PG&E proposes to use annual distribution revenue divided by the number of customers rather than usage data from DOE. For gas, it proposes to continue using DOE usage data.

SCE

SCE proposes to rely on information from its GRC or other base rate proceedings to calculate net revenues, and on information in Rule 2 of its tariffs as the basis for the COS factor.[17]

SDG&E

SDG&E recommends continued use of data from Commission decisions in ratemaking proceedings and RASS for gas.

B. Discussion

Changes to line extension allowances are routinely done through advice letter filings. Such filings are intended to be as non-controversial as possible. Therefore, the data used to calculate the allowances should have been previously adopted by the Commission or derived from such data.[18] Other possible sources may include recorded data or data adopted by other state or federal agencies.

VII. Whether Line Extension Allowances Should Continue to be Offered in Portions of the Utilities' Service Territories Where POUs are Offering Service

Currently, the investor-owned utilities (IOUs) provide the same line extension allowances throughout their individual service territories regardless of whether POUs are also offering service. The issue, as addressed herein, is whether the IOUs should be allowed to offer any line extension allowances in portions of their service territories where POUs are offering service.

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[17] SCE's Rule 2, among other things, specifies monthly ownership charges for facilities other than standard facilities SCE would normally install.

[18] Note that we adopt use of RASS herein.

A. Positions of Parties

PG&E

PG&E wishes to continue offering line extension allowances in areas served by POUs. It says that prohibiting it from doing so would be discriminatory and eliminate any meaningful choice for developers.

SCE

SCE recommends that line extension allowances not be eliminated where customers can receive POU service because the City and County of San Francisco (CCSF) and MID have not presented any quantification that would justify treating such customers differently from other customers.

SDG&E

SDG&E states that allowances should be continued in areas served by POUs, but takes no position on whether they should be different than elsewhere in the IOU's service territory.

TURN

TURN argues that the allowance calculation should be consistent across the IOUs' service territories, and the utilities should be prohibited from using ratepayer money to compete with the POUs.

CCSF

CCSF recommends that PG&E not be allowed to offer line extension allowances in areas where POUs offer service, because it has not demonstrated that it should be allowed to compete with POUs. CCSF also argues that PG&E has not shown that continuing to offer such allowances is a benefit to current ratepayers.

MID

MID takes no position on whether PG&E should be allowed to offer line extension allowances in areas where POUs offer service. However, MID states that PG&E should be allowed to do so only if PG&E demonstrates that doing so would provide an appropriate contribution to margin. MID also points out that the Commission, in D.98-06-020 expressed its support for POU-IOU competition.

CBIA

CBIA states that IOUs should be allowed to provide allowances in order to compete with POUs as long as there is a positive contribution to margin and existing ratepayers are held harmless.

B. Discussion

Our existing policy is that the IOUs are to offer uniform residential line extension allowances throughout their service territories regardless of whether a POU can provide service. The question is whether that policy should change.

POUs have the ability to offer line extension allowances. For example, the Modesto Irrigation District offers line extension allowances. Thus, prohibiting IOUs from offering line extension allowances, while the POUs can do so, would inhibit their ability to compete for new customers in those areas. As pointed out by MID, the Commission has indicated its support for such competition in the past.[19] The record does not demonstrate a need to inhibit the IOUs' ability to do so. Additionally, the record does not provide a reason to discriminate between applicants for IOU line extensions based on whether a POU may offer service. Therefore, we do not prohibit the utilities from offering the same line extension

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[19] D.98-06-020, COL 1.

allowances that are allowed in the rest of their service territories in areas where service is offered by POUs.

VIII. Criteria for Requiring a Revenue Impact Estimate to be Included in a Line Extension Allowance Change Advice Letter

General Order 96-A, Section III.C requires utilities to provide an estimate of the annual revenue effect if a tariff schedule filed in an advice letter will result in a change in revenues.[20] In D.94-12-026, the Commission adopted a settlement that, among other things, required the utilities to periodically review factors used to determine residential line extension allowances and modify the allowance if the review results in a change of over five percent. In D.98-03-039, the Commission stated "when the Commission issues a decision that impacts factors in the formula for line and service extension allowances, the utilities should apply that decision to a recalculation of the allowances without initiating or requesting a separate ratemaking or rulemaking proceeding."[21] Thus, the resulting allowance revisions have been implemented by advice letter.

A. Positions of Parties

PG&E

PG&E argues that it is not necessary to include a revenue impact estimate in allowance change advice letters. It states that revenue impacts and revenue requirements associated with line extensions have and should continue to be

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[20] D.07-01-024 adopted General Order 96-B, effective July 1, 2007, which does not contain this requirement.

[21] D.98-03-039, *mimeo.,* p. 6.

addressed in GRCs and annual true-up advice letters that reflect changes to base revenues.

PG&E proposes to update its allowances prior to the filing of phase 1 of its GRC where revenue requirements are addressed. The update would be filed early enough that the revenue requirement and, therefore, the revenue impact associated with the revised allowance could be addressed in the GRC.

SCE

SCE acknowledges that a change in the allowance could eventually affect the ratebase that, in turn, could affect rates. However, it argues that this is appropriately addressed in GRCs.

SCE recommends against DRA's proposed $5-$10 million threshold before a revenue impact estimate is needed because DRA has not provided a basis for those figures.

SDG&E

SDG&E argues that periodic changes to the allowances should have no revenue impact because they reflect changes in revenues and costs that are already built into current rates.

DRA

DRA recommends that allowances be set in GRCs. However, if the Commission decides to continue the advice letter process, DRA recommends that a revenue impact estimate be included if the impact would be greater than a specified threshold. DRA did not have a specific threshold in mind but suggested that a $5-$10 million annual revenue impact threshold should be sufficient to indicate a risk to the general body of ratepayers.

TURN

TURN stated its agreement with DRA's recommendation.

B. Discussion

An allowance change advice letter does not change rates. Changes in the allowance may eventually result in a change in ratebase that, in turn, may contribute to a change in rates. Rates change due to a number of factors in addition to a change in rate base. Thus, it would be uncertain, at the time an advice letter is filed, what any future rate change would be. For these reasons, we do not require inclusion of a revenue impact estimate in advice letter filings to revise the allowance. To the extent that an allowance change eventually contributes to a rate change, the impact should be addressed in the proceeding that makes the rate change.

IX. Cost Components to be Recovered by the Monthly COO Charge

The cost of a residential line extension is divided into two parts; non-refundable and refundable. The non-refundable costs are paid for by the applicant. The refundable costs are covered in whole or in part by the line extension allowance. The refundable costs (electric wire, gas pipe, etc.), in excess of the allowance, are advanced by the applicant to the utility. Refunds are based on the revenues from the customer residing in the dwelling and continue for up to 10 years from the date the utility is first ready to serve.

Except for individual residential applicants, when any part of the refundable costs have not qualified for a refund at the end of 12 months (36 months for gas) from the date the utility is ready to serve, a monthly COO charge is applied. The COO charge is designed to recover the costs of operating and maintaining such facilities that are not fully utilized. After 10 years, any unrefunded amounts revert to the utility. There are additional types of COO charges that apply to such things as special facilities. However, the COO charge we address in this section applies only to the refundable costs, for facilities of the type the utility would normally install, in excess of the allowance.

A. Positions of Parties

PG&E

PG&E recommends that FF&U continue to be included in the COO charge because the utility will have to pay such costs.

SCE

SCE calculates the COO charge for the unused portion of the line extension assuming it is customer-financed with replacement at additional cost. SCE believes it may be appropriate to also include replacement value in its COO charge calculation.

SCE recommends that FF&U continue to be included in the COO charge because costs, such as O&M costs and A&G costs on unutilized portions of line extensions are included in rates set in the GRC. The resulting revenues are subject to FF&U.

SDG&E

SDG&E states that its COO charge includes possible replacement by use of a sinking fund factor.

SDG&E recommends that FF&U continue to be included in the COO charge because costs, such as O&M and A&G on unutilized portions of line extensions are included in rates set in the GRC. Thus, there will be revenues subject to FF&U.

TURN

TURN states that there should be no distinction between the monthly COO charge for unused facilities (times 12) and the annual COS charge.

CBIA

CBIA states that the monthly COO charge for unused facilities should not include any charges that are revenue-based because there is no revenue generated by the unused portion of the facilities. Thus, CBIA recommends that FF&U, to the extent franchise fees are revenue-based, should not be included.

CBIA states that the COO charge should not include replacement costs, except in the 10-year refund period because replacement costs will be recovered in rates through depreciation.

B. Discussion

Based on the utilities' tariffs and submissions in this proceeding, the components of the utilities' COO charges include the following:

- O&M;
- A&G;
- Property taxes; and
- FF&U.

In addition to the above, PG&E's COO calculation assumes the facilities will be utility-financed and that 80% of the facilities will be replaced by the utility at the end of their useful lives. SCE's COO calculation assumes the facilities will be applicant-financed with replacement at additional cost to the customer. Sempra's COO calculations assume the facilities will be applicant-financed and the utility will replace the facilities in the first 10 years if needed.

As shown above, the utilities' current practices differ as to whether utility financing is assumed, and to what extent the facilities will be replaced. The other elements of the calculation are common to the utilities, and no party expressed disagreement with their inclusion except for FF&U.

Line extension facilities will have to be replaced at the end of their useful lives and, since they are owned by the utility, it will have to replace them.

Therefore, the COO charge calculation should include facility replacement for the same reasons the COS factor does.

The COO charge does not apply to the allowance. The line extension costs in excess of the allowance, to which the COO charge applies, were contributed by the applicant. Therefore, the utility has no capital investment in the facilities to which the COO charge applies and no capital-related costs should be included for them.

As to FF&U, the utility will incur O&M, A&G, and property taxes on the line extension facilities regardless of whether they are contributed by the applicant. These costs will be recovered through rates set in the GRC. The resulting revenues will result in FF&U. Therefore, FF&U is appropriate for inclusion in the COO charge.

For the above reasons, the components of the COO charge should be based on applicant financing with replacement as follows:

- O&M;
- A&G;
- Property taxes;
- FF&U; and
- Replacement of the facilities.

As is the case for the COS factor, and for the same reasons, 60 years will be used as the period during which replacements will be performed.

X. The Relationship of the Monthly COO Charge to Monthly Charge for Operations and Maintenance of Special Distribution Facilities, and the Cost of Service Factor

The COS factor is the ratio of the annual costs associated with line extension facilities to the cost of those facilities (the amount included in ratebase is the allowance).

The costs included in the COS calculation are as follows:

- O&M;
- A&G;
- Property taxes;
- FF&U;
- Replacement of the facilities;
- Income taxes;
- Return on investment; and
- Depreciation.

In addition to the COO charge discussed previously, there are COO charges that apply to special facilities.[22] Based on the utilities' tariffs and submissions in this proceeding, the components of the COO charge applicable to special facilities are as follows:

The applicant-financed COO includes the costs of:

- O&M;
- A&G;
- Property taxes; and

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[22] Special facilities are facilities requested by the applicant that are in addition to, or in substitution for, standard facilities the utility would normally provide.

- FF&U.

The utility-financed COO includes the above costs plus the following:

- Income taxes;
- Return on investment; and
- Depreciation.

In addition to the above, PG&E includes replacement at the end of the facilities' useful lives. SCE includes replacement in perpetuity and, in some cases, offers replacement options of no replacement (the customer would pay for replacement) and replacement for 20 years after which the customer would pay for replacement. Sempra includes replacement of the facilities in the first 10 years, if needed.

A. Positions of Parties

PG&E

PG&E states that its COS factor is 12 times its COO charge.

TURN

TURN states that the only difference between the COO charge for unused portions of line extensions and the COO charge for special facilities should be that the COO charge may have options as to whether the facilities are utility financed, over what time the facilities are financed, and for what period of time replacement costs are included.

CBIA

CBIA states that the COO charge for unused facilities and special facilities should be the same and should not include depreciation and return because the facilities are paid for by the applicant.

CBIA argues that the COS factor represents utility-financed facilities and should include depreciation and a return on the investment.

B. Discussion

As shown above, the utilities' COO charges applicable to special facilities contain the following elements:

The applicant-financed COO charge includes the costs of:

- O&M;
- A&G;
- Property taxes;
- FF&U; and
- Replacement of the facilities.

The utility-financed COO charge includes the above costs plus the following:

- Income taxes;
- Return on investment; and
- Depreciation.

The only difference between the utilities' methodologies is due to the time over which replacement by the utility is covered.

The COO charge applicable to special facilities and the COO charge applicable to refundable costs should be the same if the special facilities are applicant-financed and replacement is provided for the same period of time. This is reasonable since both charges would be recovering the same costs. If the special facilities are utility-financed, we would expect the utility to recover income taxes, return on the investment, and depreciation. Likewise, if replacement of the facilities is included by the utility, the charge should include the cost of replacements. The utilities' calculation methodologies for the COO charge applicable to special facilities meet these requirements and we find them reasonable.[23]

Based on the above discussion, the COS factor should not equal 12 times the COO charge applicable to refundable costs because the COO charge does not include utility-financing of the costs to which it applies whereas the COS factor includes utility financing of the allowance. However, the monthly COO charge applicable to special facilities would be equal to one twelfth of the COS factor if the special facilities are utility financed and the utility pays for replacement over the same period.

XI. Whether SCE's Sub-Transmission Costs Should be Considered Distribution Costs for the Purpose of Calculating the Line Extension Allowance

A. Positions of Parties

SCE

SCE states that sub-transmission costs should be included in the net revenue calculation because they are similar to other distribution costs and are recovered through distribution rates.

TURN

TURN states that SCE's sub-transmission costs should not be considered distribution costs for the purpose of determining line extension allowances because residential customers are not served at the sub-transmission level, and sub-transmission costs are not directly associated with line extensions.

CBIA

23 In these proceedings, we address the calculation of the COO charge applicable to special facilities, but not its application.

CBIA states that electric sub-transmission costs should be included in net revenues because such facilities are radial feeds to large customers at higher than normal voltage levels and are not used to serve substations that subsequently provide distribution services at normal distribution voltages.

B. Discussion

Unlike PG&E and SDG&E, SCE's sub-transmission costs are recovered in residential distribution rates. Inclusion of such revenues in the net revenue calculation is consistent with the Commission's policy that the allowance should be revenue-justified. Thus, we do not remove SCE's sub-transmission costs from the net revenue calculation.

XII. TURN's Proposal to Reduce and Freeze the Allowance

Line extension allowances go into ratebase. TURN argues that because the allowances increase ratebase, they cause rates to increase. The increase then leads to higher net revenues, which leads to higher allowances. Thus, TURN argues that the Commission's method of calculating line extension allowances results in perpetual rate increases. As a result, TURN recommends that the current allowances be reduced by 20%, and frozen for five years. TURN states that the Commission could use data gathered over the freeze period to determine whether there is a resulting effect on capital spending, rates and new customer hookups, and to determine whether the allowance should be adjusted for inflation.

SCE and Sempra state that TURN has not justified the freeze or reduction.

This proceeding is limited to the issues identified in the scoping memo. The only issues identified in the scoping memo to which TURN's recommendation could be related are:

- Calculation of the net revenue on which line extension allowances are based; and
- Whether the COS factor should account for replacement in perpetuity.

TURN's proposal does not address the calculation of the net revenue or the COS factor. Therefore, it falls beyond the scope of this proceeding and will not be adopted.

XIII. TURN's Proposal to Restrict Gas Allowances

TURN proposes that customers not be given an allowance for space heating or water heating unless gas will be used for both. TURN states that this will eliminate uneconomic substitution of electricity for gas. TURN also points out that it is virtually impossible to pass the CEC's Title 24 building efficiency standards and install electric water heating where gas is available.

Sempra opposes TURN's recommendation because it would reduce the service options available to the applicant.

TURN's proposal would discourage use of electric resistance space heating and water heating where gas is available. However, there may be cases where gas is available, but use of tankless point-of-use electric water heaters or electric heat pumps for space or water heating is appropriate. The record does not contain sufficient information for us to address this possibility. Thus, we do not adopt TURN's recommendation.

XIV. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments and/or reply comments were filed by PG&E, SCE, Sempra, CCSF, CBIA, TURN, and DRA. All comments were considered. Changes have been made, as necessary, to reflect the comments.

In its comments, PG&E argues for approval of its request that any change to base costs that result from these proceedings be considered incremental to its 2007 GRC. It further argues that it should be permitted to file advice letters to record approved changes to base revenues and to recover such costs through the already-established annual gas and electric true-up advice letters. PG&E includes its request under the issue "Criteria for requiring a revenue impact estimate to be included in a line extension allowance change advice letter."

PG&E's request was not identified as an issue in the scoping memo for this proceeding. The issue PG&E includes its request under concerns criteria for determining whether advice letters requesting a change to the line extension allowance should include an estimate of the revenue impact of the allowance change. PG&E's request addressing a mechanism for recovery of such costs does not fit within that issue, is beyond the scope of this proceeding, and need not be addressed.

XV. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Jeffrey P. O'Donnell is the assigned ALJ in this proceeding.

Findings of Fact

1. D.97-12-098 states: "applicants should receive such free allowances only to the extent that the revenue expected to be received from the load to be served matches the utility's investment…ratepayers will not be overpaying in those allowances for revenues that will never materialize."

2. Costs related to distribution facilities, including line extension allowances, are recovered only through distribution rates.

3. Distribution revenues are the appropriate starting point for determining net revenue.

4. Since average distribution revenue per residential customer is the average amount of revenue that can be expected to be received from the average residential customer, it is the amount available to pay for the allowance.

5. Net revenue cannot exceed the average distribution revenue per residential customer.

6. In D.94-12-026, the Commission defined net revenue as: "That portion of the total rate that supports the utility's extension costs and excludes such things as fuel costs and other energy adjustment costs that do not support the extension costs." The Commission also determined that the allowances should be "revenue-based." That is, the allowances "would be based on the expected supporting revenues from the loads to be served by the extension."

7. In D.97-12-098, the Commission determined that line extension allowances should be "revenue justified." That is, allowances should be set such that the revenue expected to be received from the load to be served "matches" the utility's investment. The Commission also decided that the allowance should be distribution-based to reflect the unbundling of utility rates.

8. In D.94-12-026 and D.97-12-098, the Commission did not precisely define what it meant by revenues that "support" line extension costs or "match" the utility's investment.

9. There is no precise definition of what net revenues should include.

10. In D.94-12-026 and D.97-12-098, the Commission established its overall policy that the allowance should be revenue justified based on distribution revenues expected to be received from the residents of new dwellings.

11. In order for the line extension allowance to be an unreasonable subsidy, the costs of the allowance must exceed its benefits.

12. The allowance is provided by residential ratepayers.

13. The record shows that the primary direct beneficiary of the allowance is the developer.

14. Only two possible ratepayer benefits of the allowance to ratepayers have been identified in the record; a positive contribution to margin, on average, due to the addition of new dwellings, and a reduction in housing prices (new dwellings and the housing market as a whole).

15. Since it is not reasonable to assume that provision of the allowance is the sole reason that a new dwelling will be built, only some portion of the contribution to margin generated by the addition of a new dwelling would be due to the allowance.

16. Nothing in the record demonstrates what the contribution to margin would be, much less how much of any positive contribution would be due to the allowance.

17. If the new dwelling is rented, the only direct benefit to the renter would be a reduction in the rent due to a reduction in the cost of the dwelling.

18. The allowance reduces the total cost to construct a dwelling.

19. Elimination of the line extension allowances would have a 0.19% effect on new housing prices ($650,000).

20. Since the record does not indicate that prices charged by developers for new dwellings are strictly cost-based, it does not indicate what benefit the owner of a new dwelling will actually receive from the allowance.

21. Since the record does not indicate that the rent charged for a new dwelling will be strictly cost-based, it does not indicate what benefit the renter of a new dwelling will actually receive from the allowance.

22. Since the record does not demonstrate that the allowance will have a material effect on the overall price of housing, the record does not indicate what benefit customers residing in existing dwellings will receive.

23. The record does not indicate whether there is a significant benefit to ratepayers due to a reduction in new and/or existing housing prices, much less what the value of any benefit would be.

24. DRA's and TURN's references to "new customers" refer to customers residing in new dwellings and/or developers.

25. Since the record is insufficient to determine what benefits ratepayers receive from the allowance, and does not address whether there are other unquantified benefits of the allowance, it is unknown whether the allowance constitutes an unreasonable ratepayer subsidy of developers or customers residing in new dwellings.

26. The Commission's current formula for calculating the line extension allowance was previously determined by the Commission to be reasonable.

27. For the Commission to revise its line extension allowance calculation formula, as recommended by DRA and TURN, it would have to determine that there is an unreasonable subsidy and that TURN's and/or DRA's recommendations would reduce or eliminate the unreasonableness of the subsidy.

28. In D.98-09-070, the Commission directed PG&E, SCE, and SDG&E to propose changes to the line extension rules that remove revenues associated with unbundled revenue cycle services from the line extension allowance calculation.

29. In D.99-12-046, the Commission removed the RCS credit from the electric line extension allowance calculation.

30. Direct access electric service is not currently available to new customers, but may be resumed in the future.

31. Since a customer residing in a new dwelling may eventually take direct access service, future revenues from the customer may be reduced by the amount of the RCS credits.

32. RCS credits are appropriate for exclusion from the net revenue calculation because they represent lost revenues due to direct access.

33. The electric net revenue calculation should reflect factors, such as rate discounts, that may impact revenues because customers residing in new dwellings may receive such discounts.

34. The use of total electric residential distribution revenues divided by the number of customers would reflect average revenue per customer including baseline usage, discounts, etc.

35. Since most new dwellings are built by developers and the customer who will live there can not be identified until the dwelling is sold, whether that customer will receive a rate discount will likely be unknown when the allowance is provided to the developer.

36. Subsequent residents of a new dwelling may or may not receive a rate discount.

37. Developers are eligible to receive from the utilities 50% of the refundable line extension costs in excess of the allowance rather than refunds based on additional services or line extensions subsequently connected to the applicant's line extension. Whether this comprises a discount to the developer depends on whether additional services and/or line extensions are subsequently connected

to the applicant's line extension, which will not be known at the time the allowance is calculated.

38. For gas line extension allowances, no equivalent of the electric RCS credits is subtracted from average residential distribution revenues in the net revenue calculation.

39. TURN's recommendation to remove downstream customer costs from gas net revenues is essentially the same as its recommendation that marginal customer service costs be removed from electric net revenues instead of RCS credits, and its reasoning is essentially the same.

40. Revenue cycle services have not been unbundled for gas, no gas equivalent of the RCS credit has been established for gas utilities as a whole, and we have not required that such a credit be deducted from gas net revenues.

41. The gas appliance usages used to determine the allowance should reflect the usages in each utility's service area, rather than aggregate California usage as used by PG&E.

42. The RASS survey is implemented at the direction of the CEC to determine appliance saturation and usage for each of the participating utilities.

43. PG&E and Sempra participate in the RASS.

44. The average residential gas distribution rate is multiplied by the appliance usages to determine the net revenue.

45. Local gas transmission costs are not recovered in residential gas distribution rates.

46. Inclusion of local gas transmission revenues in the gas net revenue calculation would not be revenue justified.

47. Once a line extension has been installed, its maintenance and replacement become the utility's responsibility.

48. No party has suggested that the life of a residential dwelling is limited to the life of the line extension.

49. The overall life of line extension facilities is approximately 30 years, with the lives of some components being longer and some shorter.

50. The utility will have to replace the line extension at the end of its useful life.

51. No party has provided evidence as to how long a residential dwelling will last on average.

52. It is common knowledge that residential dwellings, although they won't last forever, can last well in excess of 60 years.

53. The purpose of depreciation is to recover the original capital cost of facilities, adjusted for any salvage and/or removal costs, over their useful lives.

54. Depreciation does not provide for replacement of the facilities at the end of their useful lives.

55. Inclusion of depreciation in the COS factor calculation does not provide for replacement in perpetuity.

56. Net revenue is intended to be those CPUC jurisdictional revenues that will be paid to the utility and can be used to pay the costs of the line extensions.

57. Since distribution rates include costs for replacements of line extension facilities during the forecast period because they are the utility's responsibility, the net revenue based on those rates includes replacements.

58. PG&E and Sempra represent that their COS factor calculations include replacements, but they do not adjust their net revenue calculations due to that fact.

59. Changes to line extension allowances are routinely done through advice letter filings, which are intended to be as non-controversial as possible.

60. The Commission's existing policy is that the IOUs are to offer uniform residential line extension allowances throughout their service territories regardless of whether a POU can provide service.

61. POUs have the ability to offer line extension allowances.

62. Prohibiting IOUs from offering line extension allowances, while the POUs can do so, would inhibit their ability to compete for new customers in those areas.

63. In D.98-06-020, the Commission indicated its support for IOU/POU competition.

64. The record does not demonstrate a need to inhibit the IOUs' ability to compete with POUs or a reason to discriminate between applicants for IOU line extensions based on whether a POU may offer service.

65. General Order 96-A, Section III.C requires utilities to provide an estimate of the annual revenue effect if a tariff schedule filed in an advice letter will result in a change in revenues.

66. In D.94-12-026, the Commission adopted a settlement that, among other things, required the utilities to periodically review factors used to determine residential line extension allowances and modify the allowance if the review results in a change of over five percent.

67. In D.98-03-039, the Commission stated "when the Commission issues a decision that impacts factors in the formula for line and service extension allowances, the utilities should apply that decision to a recalculation of the allowances without initiating or requesting a separate ratemaking or rulemaking proceeding."

68. Line extension allowance revisions have been implemented by advice letter.

69. An allowance change advice letter does not change rates.

70. Changes in the allowance may eventually result in a change in ratebase that, in turn, may contribute to a change in rates.

71. Since rates change due to a number of factors in addition to a change in rate base, it would be uncertain when an advice letter is filed what any future rate change would be.

72. The COO charge, applicable to the refundable costs, for facilities of the type the utility would normally install, in excess of the allowance is designed to recover the costs of operating and maintaining such facilities.

73. The components of the utilities' COO charges applicable to refundable costs in excess of the allowance include O&M, A&G, property taxes, and FF&U, and no party expressed disagreement with their inclusion, except for FF&U.

74. The components of the utilities' COO charges applicable to refundable costs in excess of the allowance differ as to whether utility financing is assumed, and to what extent the facilities will be replaced.

75. Line extension facilities will have to be replaced at the end of their useful lives and, since they are owned by the utility, it will have to replace them.

76. The COO charge applicable to refundable costs in excess of the allowance does not apply to the allowance.

77. Refundable costs in excess of the allowance are contributed by the applicant.

78. The utility will incur O&M, A&G, and property taxes on the line extension facilities regardless of whether they are contributed by the applicant. These costs will be recovered through rates set in the GRC. The resulting revenues will result in FF&U.

79. The COS factor includes O&M, A&G, property taxes, FF&U, replacement of the facilities, income taxes, return on investment, and depreciation.

80. COO charges applicable to special facilities vary depending on whether the facilities are utility financed or customer financed, and whether replacement is included and for how long.

81. The applicant-financed COO charge applicable to special facilities includes the costs of O&M, A&G, property taxes, FF&U.

82. The utility-financed COO charge applicable to special facilities includes the costs of O&M, A&G, property taxes, FF&U, plus income taxes, return on investment and depreciation.

83. PG&E's COO charges applicable to special facilities include replacement at the end of the facilities' useful lives.

84. SCE's COO charges applicable to special facilities include replacement in perpetuity and, in some cases, SCE offers replacement options of no replacement (the customer would pay for replacement) and replacement for 20 years after which the customer would pay for replacement.

85. Sempra's COO charges applicable to special facilities include replacement of the facilities in the first 10 years, if needed.

86. The only difference between the utilities' methodologies for calculating the COO charge applicable to special facilities is due to the time over which replacement by the utility is covered.

87. The COO charge applicable to special facilities and the COO charge applicable to refundable costs should be the same if the special facilities are applicant-financed and replacement is provided for the same period of time because both charges would be recovering the same costs.

88. The COS factor should not equal 12 times the COO charge applicable to refundable costs because the COO charge does not include utility-financing of the costs to which it applies whereas the COS factor includes utility financing of the allowance.

89. The monthly COO charge applicable to special facilities would be equal to one twelfth of the COS factor if the special facilities are utility financed and the utility pays for replacement over the same period.

90. SCE's sub-transmission costs are recovered in residential distribution rates.

91. Inclusion of revenues associated with SCE's sub-transmission costs in the net revenue calculation is consistent with the Commission's policy that the allowance should be revenue justified.

92. TURN's recommendation that the current allowances be reduced by 20%, and frozen for five years falls beyond the scope of this proceeding.

93. TURN's proposal that customers not be given an allowance for space heating or water heating unless gas will be used for both would discourage use of electric resistance space heating and water heating where gas is available.

94. There may be cases where gas is available, but use of tankless point-of-use electric water heaters or electric heat pumps for space or water heating is appropriate, and the record does not contain sufficient information to address this possibility.

95. PG&E's request that the result from these proceedings be considered incremental to its 2007 GRC, and that it be permitted to file advice letters to record approved changes to base revenues and to recover such costs through the already-established annual gas and electric true-up advice letters is beyond the scope of this proceeding.

Conclusions of Law

1. Since DRA and TURN have not shown that the line extension allowance constitutes an unreasonable subsidy, that their recommended subtraction of specified costs from the net revenue calculation would reduce or eliminate the unreasonableness of the subsidy, and that their recommendations are more reasonable than the Commission's current calculation methodology, their recommendations should not be adopted.

2. DRA's and TURN's recommendation to subtract the utility's marginal customer cost from the net revenue calculation, rather than RCS credits, should not be adopted.

3. Since we do not adopt DRA's and TURN's recommendations regarding net revenues, we should not limit allowance changes to GRCs and BCAPs.

4. Electric net revenue should be based on the average distribution revenue per residential customer calculated as the total residential distribution revenue divided by the total number of residential customers.

5. Since residential rate discounts are usually paid for by other residential customers, if the cost of a discount is not included in residential rates, but recovered separately from residential customers through a surcharge, the revenue reduction due to the discount should be excluded from the electric net revenue calculation.

6. MID's proposal to calculate customer-specific discounts for customers who receive rate or line extension cost discounts should not be adopted.

7. TURN's recommendation to remove downstream customer costs from gas net revenues should not be adopted.

8. RASS should be used to determine average household gas appliance usage for each type of use.

9. The average residential gas rate should reflect factors, such as rate discounts, that may impact revenues because customers residing in new dwellings may receive such discounts.

10. The average residential gas rate should be calculated as total residential revenues divided by total residential usage.

11. Since residential rate discounts are usually paid for by other residential customers, if the cost of a discount is not included in residential rates, but recovered separately from residential customers through a surcharge, the revenue reduction due to the discount should be excluded from the average gas rate calculation.

12. PG&E's proposal to include local gas transmission revenues in the net revenue calculation should not be adopted.

13. The Commission should require that replacement be included in the calculation of the COS factor.

14. Since we do not know how long residential dwellings will last on average and they will not last forever, 60 years should be used as the period during which replacements will be performed.

15. The Commission should not adjust net revenues due to inclusion of replacement in the COS factor.

16. Since we do not adopt DRA's and TURN's recommendations for subtracting certain marginal costs from net revenues, we need not address whether adoption of their recommendations would necessitate a change in how the COS factor is calculated.

17. Data used to calculate the allowances should include data that have been previously adopted by the Commission or derived from such data, recorded data, or data adopted by other state or federal agencies.

18. The Commission should not prohibit the utilities from offering the same line extension allowances that are allowed in the rest of their service territories in areas where service is offered by POUs.

19. The Commission should not require inclusion of a revenue impact estimate in advice letter filings to revise the allowance.

20. The COO charge applicable to refundable costs in excess of the allowance calculation should include facility replacement for the same reasons the COS factor does.

21. The COO charge applicable to refundable costs in excess of the allowance should not include capital-related costs.

22. The components of the COO charge applicable to refundable costs in excess of the allowance should include O&M, A&G, property taxes, FF&U and replacement of the facilities for 60 years.

23. For the COO charge applicable to refundable costs in excess of the allowance, 60 years should be used as the period during which replacements will be performed for the same reasons as the COS factor.

24. If the special facilities are utility-financed, the COO charge should include income taxes, return on the investment, and depreciation.

25. If replacement of the special facilities is included by the utility, the COO charge should include the cost of replacements.

26. The utilities' calculation methodologies for the COO charge applicable to special facilities meet the requirements of Conclusions of Law 25 and 26, and are reasonable.

27. SCE's sub-transmission costs should not be removed from the net revenue calculation.

28. TURN's recommendation that the current allowances be reduced by 20%, and frozen for five years should not be adopted.

29. TURN's recommendation that customers not be given an allowance for space heating or water heating unless gas will be used for both should not be adopted.

30. PG&E, SCE, SDG&E, and SCG should be ordered to file advice letters to implement the above requirements including any necessary changes to their line extension allowances or their COO charges applicable to refundable costs in excess of the line extension allowances.

31. Since PG&E's request that the result from these proceedings be considered incremental to its 2007 GRC, and that it should be permitted to file advice letters to record approved changes to base revenues and to recover such costs through the already-established annual gas and electric true-up advice letters is beyond the scope of this proceeding, it need not be addressed.

32. Hearings were necessary in these proceedings.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company shall file advice letters, within 120 days of the effective date of this order, to implement the refinements to their electric and gas line and service extension allowance calculations specified below, including any necessary changes to their electric and/or gas line and service extension allowances and/or their cost of ownership (COO) charges applicable to refundable costs in excess of the line and service extension allowances.

2. Electric net revenue shall be based on the average distribution revenue per residential customer calculated as the total residential distribution revenue divided by the total number of residential customers.

3. If the cost of an electric distribution rate discount is not included in residential electric distribution rates, but recovered separately from residential customers through a surcharge, the revenue reduction due to the discount shall be excluded from the calculation of average electric distribution revenue per residential customer.

4. The results of the most recent California Residential Appliance Saturation Survey, implemented at the direction of the California Energy Commission, shall be used to determine average household appliance usage for each type of gas use.

5. The average residential gas distribution rate shall be calculated as total residential gas distribution revenues divided by total residential gas usage.

6. If the cost of a gas residential distribution rate discount is not included in residential gas distribution rates, but recovered separately from residential customers through a surcharge, the revenue reduction due to the discount shall be excluded from the average gas distribution rate calculation.

7. Replacement for 60 years shall be included in the calculation of the electric and gas cost of service factors.

8. Data used to calculate the electric and gas line and service extension allowances shall include data that have been previously adopted by the Commission or derived from such data, recorded data, or data adopted by other state or federal agencies.

9. The calculation of the electric and gas COO charges applicable to refundable costs in excess of the line and service extension allowance shall include facility replacement for 60 years, and shall not include capital-related costs.

10. Application (A.) 05-09-019, A.05-10-016, and A.05-10-019 are closed.

This order is effective today.

Dated July 12, 2007, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

ATTACHMENT A

LIST OF ACRONYMS

Acronym	Name
A&G	administrative and general
A.	Application
BCAPs	Biennial Cost Allocation Proceedings
CARE	California Alternative Rates for Energy
CBIA	California Building Industry Association
CCSF	City and County of San Francisco
CEC	California Energy Commission
COO charge	cost of ownership charge
COS Factor	Cost of Service Factor
D.	Decision
DOE	United States Department of Energy
DRA	Division of Ratepayer Advocates
EPMC	Equal Percentage Marginal Cost
FF&U	franchise fees and uncollectibles
GRC	general rate case
IOUs	investor-owned utilities
MID	collectively Modesto Irrigation District and the Merced Irrigation District
O&M	operations and maintenance
PG&E	Pacific Gas and Electric Company
POUs	publicly-owned energy utilities

RASS	California Residential Appliance Saturation Survey
RCS	revenue cycle service
SCE	Southern California Edison Company
SCG	Southern California Gas Company
SDG&E	San Diego Gas & Electric Company
Sempra	collectively SDG&E and SCG
TURN	The Utility Reform Network

(END OF ATTACHMENT A)