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Fair Market Value As of January 1, 2008

PG&E Yolo County Electric Properties SMUD Proposes to Condemn

September 2005

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September 16, 2005

Mr. Thomas E. Bottorff
Senior Vice President, Customer Service and Revenues
Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94177-0001

Dear Mr. Bottorff

We are enclosing our report titled "Fair Market Value as of January 1, 2008, of PG&E Yolo County Electric Properties, SMUD Proposes to Condemn".

As explained more fully below, we find the fair market value as of January 1, 2008 for PG&E's property that SMUD proposes to condemn amounts to $515.44 million. This amount exceeds estimates of value set forth in reports prepared by R.W. Beck (Beck) and SMUD Staff (Staff). Based on our review of the two reports, we find a number of errors and omissions on their part that contribute to their much lower value.

Any reasonable study of the economic consequences of SMUD condemning facilities in the area in question must be based on a reasonable determination of the amount the condemnation court will award PG&E for the property. Our value of $515.44 million is such an estimate. We recommend that any study of the economic consequences of SMUD condemning the property assume a payment of not less than $515.44 million ($565.88 million including stranded investment and severance) to PG&E for the property, assuming a January 1, 2008 takeover date.

On July 29, 2005, the Sacramento Municipal Utility District (SMUD) petitioned the Sacramento County Local Agency Formation Commission (LAFCo) for approval to annex into its service territory certain electric utility service areas currently served by the Pacific Gas and Electric Company (PG&E). SMUD requests permission to take PG&E's service areas in the Cities of Davis (with the exception of the UC Davis Campus), West Sacramento, and Woodland, California, as well as certain unincorporated areas of Yolo County, California

The purpose of our report is to describe the detailed analysis underlying Black & Veatch's independent determination of the fair market value of the facilities under consideration. Since PG&E has repeatedly stated that these properties are not for sale, we determine fair market value consistent with our understanding of the statutory requirements and case law applicable to the condemnation of utility property.

<u>The area identified by SMUD in its July 29, 2005 LAFCo application differs materially from the area defined by Beck and Staff in reports they prepared regarding the value of facilities and the economic feasibility of SMUD annexing and serving parts of Yolo County</u>. LAFCo's July 17, 2005 letter to PG&E requested information about the area defined by Beck and Staff, not the different area identified by SMUD's July 29 LAFCo application. For the purpose comparability and to comply with LAFCo's

request, this report values PG&E's property in the area specified by Beck, Staff, and LAFCo's July 17 letter. We refer to this area as the "original" area, and the area identified in SMUD's July 29 LAFCo application as the "new" area. The new area is larger than the original area, but does not cover all of the original area. The new area contains more electric facilities and customers, so its fair market value is likely to be greater than the value for the original area developed in this report. In Appendix 1.0, we discuss some of the differences between the original and new areas.

Similarly, Beck and Staff valued the facilities to be taken as of December 31, 2004 – even though neither Beck nor Staff assumes SMUD would acquire PG&E's Yolo facilities by that date. Based on Beck's and Staff's economic analysis, they apparently project January 1, 2008 as the taking date. SMUD in its July 29 LAFCo application moves that date back to October 1, 2008. Therefore, SMUD not only fails to support its LAFCo application with a valuation of the facilities it requests permission to condemn, SMUD fails to support its LAFCo application with an economic assessment that corresponds to the new area and its assumed date of the takeover.

By valuing the facilities as of year-end 2004, Beck and Staff ignored the capital additions, depreciation, retirements, replacements, growth, price level changes, and other factors that will influence the facilities' fair market value over the next several years. This report values the PG&E facilities as of January 1, 2008, and provides an estimate as of October 1, 2008.

The report consists of nine sections plus appendices. These sections include:

- **Section 1:** Executive Summary
- **Section 2:** Introduction and Qualifications
- **Section 3:** General Considerations – In this section we outline general considerations in valuing property and the general nature of electric utility property.
- **Section 4:** Facilities Under Consideration – In this section we describe the electric utility property in the original area, how we identified the property in the area, and our determination of the replacement cost new less depreciation (RCNLD) value of this property as of December 31, 2004.
- **Section 5:** RCNLD as of January 1, 2008 – In this section we describe the adjustments we make to our December 31, 2004 RCNLD value to reflect a reasonable estimate of the fair market value as of January 1, 2008, the earliest date we assume SMUD can take ownership.
- **Section 6:** Going Concern Value – In this section we describe our measure of the additional value of PG&E's property by virtue of its assembly and use to support PG&E's ongoing and potential future business activities and SMUD's desire to use this property in the same manner.
- **Section 7:** Total Value: **-** In this section we summarize our determination of total fair market value as of January 1, 2008. In our determination of total value we include allowances for other PG&E assets to be acquired or affected by SMUD's proposed taking, and PG&E liabilities which SMUD will assume upon takeover. We also develop an estimate of fair market value as of October 1, 2008.
- **Section 8:** Critique of R.W. Beck and SMUD Staff Estimates – Prior to SMUD's July 29 application to LAFCo, Beck and Staff prepared estimates of the value of PG&E facilities in the original area. The Beck and Staff estimates of value are substantially below ours. In this section, we describe differences in the estimates and the factors that contribute to Beck's and Staff's understatements of value. In addition to the Beck and staff reports, Dr. Sanjay Varshney prepared a report dated May 5, 2005 titled "Independent Consultant Review of Annexation Feasibility Study". While we do not agree with many of Dr. Varshney's findings and conclusions, based on our review of

this report, we find no independent analytical analysis not presented in the Beck and/or Staff reports. We therefore do not separately address Dr. Varshney's report.

Section 9: Detailed Tables – In this section we include detailed information supporting the summary level information we include in Sections 1 through 8.

Section 10: Appendices – In the appendices, we provide further detailed information, supporting summary information we include in Sections 1 through 9.

In our report, we have numbered tables and figures to correspond to the various sections and subsections in order to facilitate reference between the text and the various tables and figures.

As shown in Sections 1 and 7, we find the fair market value of PG&E's facilities proposed for condemnation in the original area to amount to $515.44 million as of January 1, 2008 ($565.88 million including stranded investment and severance). Based on the change in replacement cost new less depreciation between December 31, 2004 and January 1, 2008, we estimate a fair market value of $580.60. million as of October 1, 2008 (including stranded investment and severance).

As we describe more fully in Section 8, we find that Beck and Staff materially understate value due to:

1. Failing to include any costs to place underground equipment underground
2. Understating by 1/3, the amount of underground distribution lines in service
3. Failing to include land rights required to access PG&E's distribution facilities
4. Failing to include price level increases and PG&E's capital additions between the end of 2004 and the January 1, 2008
5. Failing to include going concern value
6. Failing to include other PG&E assets for which SMUD must compensate PG&E
7. Improperly calculating depreciation
8. Improperly calculating salvage cost

In short, the estimates of value set forth in the Beck and Staff reports do not represent a measure of the amount that SMUD can reasonably expect a condemnation court to order as the amount due PG&E for taking the property.

We appreciate this opportunity to assist PG&E and the assistance provided by PG&E professionals, in particular Mark Penskar, Chuck Wagenseller, and Don Hellier, in preparing this report.

If you have any questions concerning the contents of the report, please contact me at your convenience.

Very Truly Yours,
Black & Veatch Corporation

L.W. Loos
Director, Enterprise Management Solutions

Enclosure

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1.0 Executive Summary

As explained more fully below, we find $515.44 million as the fair market value (as of January 1, 2008) for PG&E's property in the original area SMUD proposes to condemn. This amount exceeds estimates of value set forth in reports prepared by R.W. Beck and SMUD Staff as a result of a number of errors and omissions on their part. Any reasonable study of the economic consequences of SMUD condemning facilities in the original area must be based on a reasonable determination of the amount the condemnation court will award PG&E for the property. Our value of $515.44 million is such an estimate. We recommend that any study of the economic consequences of SMUD condemning the property rely on a payment of not less than $515.44 million ($565.88 million including stranded investment and severance) to PG&E for the property.

1.1 Background

In January 2005, R.W. Beck, Inc., (Beck) in association with Stone & Webster Management Consultants, Inc. and Lucy & Company, prepared a study entitled "Sacramento Municipal Utility District Annexation Feasibility Study". In this study, Beck ascribes a value to the facilities generally corresponding to those in the original area proposed for condemnation of $102 million. This value is based on a replacement cost new of $201 million less depreciation of $99 million.

Following the release of Beck's report, PG&E, with assistance and direction from Black & Veatch, prepared an initial rough estimate of the value of PG&E's facilities in the original area identified by Beck. This value substantially exceeds that estimated by Beck.

In April 2005, SMUD Staff (Staff) prepared a study titled "Yolo Annexation Feasibility Study Staff's Assessment and Recommendations" in which Staff ascribes a value to the electric utility system SMUD proposes to condemn of $130 million. This value is based on replacement cost new of $245 million less depreciation of $115 million. Staff's estimate of value, while greater than Beck's, remains substantially below PG&E/Black & Veatch's preliminary estimate.

By letter dated July 17, 2005, the Sacramento Local Agency Formation Commission (LAFCo) informed PG&E of an expected application from SMUD proposing to annex certain Yolo County territory served by PG&E and requesting certain data of PG&E. LAFCo attached to the July 17, 2005 letter a map of the area that LAFCo anticipated SMUD desires (see Figure 4.1.1). The area encompassed in this map corresponds to the original area identified by Staff in its April report, and by Beck in its January 2005 report.

In this report, we describe our independent determination of the fair market value of PG&E's electric utility properties used to directly serve its customers in the original area identified by Staff and LAFCo's July 17 letter. In our determination, we are guided by the original area defined as well as by the distribution substations and transmission lines Staff identifies as facilities SMUD proposes to condemn.

On July 29, 2005, SMUD submitted its "Application for Annexation of the Cities of West Sacramento, Davis, and Woodland, and Unincorporated Areas of Yolo County and Related Sphere of Influence Amendment." In its application, SMUD requests permission to annex an area that differs from the area identified in the July 17, 2005 letter from LAFCo to PG&E and the Staff and Beck reports. In this report, we value facilities in the area identified in LAFCo's July 17, letter ("original area"). We do not develop value corresponding to the area identified by SMUD in its July 29 Application ("new area"). We are unaware of any estimate of value to date, for the facilities serving this new area, or any assessment of the economics of SMUD serving this area. In Appendix 1.0, we discuss differences between the original and new areas.

1.2 Fair Market Value

PG&E counsel informs us that SMUD's taking of PG&E's property is governed by California Eminent Domain Law. That law requires SMUD to pay PG&E "fair market value of the property taken" (Cal. Code of Civil Procedure §1263.310). "Fair market value" is

> "the *highest price* on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available" (Id. §126.320(a); emphasis added.)

Most valuation experts and courts recognize three general approaches to measure fair market value. These three approaches are market, earnings, and cost based measures.

In connection with the condemnation of rate regulated properties, such as PG&E's electric transmission and distribution systems, courts have generally recognized use of cost based measures, in particular reproduction and replacement cost new less depreciation. Replacement cost new less depreciation (RCNLD) is a valuation method specifically approved by California statute for valuing improvements to land, such as the electric facilities here in issue (Cal. Evidence Code §820). For the purpose of this report, we develop the value of PG&E's property SMUD proposes to condemn using the RCNLD measure.

1.3 Equipment Inventory

In our development of RCNLD, we first develop a value for PG&E's property in service as of December 31, 2004 based on cost levels and conditions corresponding to the end of 2004. We develop an inventory of PG&E's property in service based on PG&E's records maintained in the normal course of business. As more fully described in Section 4, PG&E relies on a geographic information system (GIS) to link property data to specific geographic areas. By use of this system, with the assistance of PG&E professionals, we are able to identify the specific circuits serving the area and the specific detailed maps which show PG&E's equipment. Within the area defined in Figure 4.1.1, PG&E relies on 266 detailed (plat) maps. PG&E maintains much of the information contained in these maps in several different databases. The databases contain certain information regarding all distribution equipment except substations, meters, and services.

Based on the area described, we develop a detailed inventory of equipment in the area. A summary level listing of equipment in the area includes:

Transmission Lines:	
Not Stranded:	75.59 circuit miles
Stranded	61.59 circuit miles
Distribution Land and Rights:	2,300 parcels
Substation Capacity:	
Not Stranded	386 MVA
Stranded	420 MVA
Overhead Feeders:	537 circuit miles
Underground Feeders:	354 circuit miles
Number of Customers:	69,259
Number of Line Transformers:	8,838

We tested the validity of the inventory we developed from PG&E's various databases, by conducting full field inventories in a number of areas. Each of the selected areas corresponds to one of PG&E's 266 detailed plat maps, within the original area. During the field inventory, we rely on the detailed maps to help physically locate pieces of equipment. Once we locate a piece of equipment, we add it to the inventory for that area.

We also query PG&E's various databases for equipment in the specific geographic area to determine an inventory based on the databases. We compare the inventory developed from our field inspections with the one developed from the databases to evaluate the accuracy of the database inventory. Our study shows that PG&E's database inventory compares favorably with the inventory developed from field inspections. In fact, the databases more often understated the inventory than overstated it, so it is probable that a full field inventory of the original area would find more equipment in use to serve customers than we identify in this report. To the extent our inventory fails to include all property in the area, we likely understate value.

1.4 Replacement Cost New

In order to develop RCN, we develop the cost today of constructing the system. To develop our RCN value, we rely on unit costs based on PG&E's Job Estimating Tool (JET). For transmission lines and distribution substations, we rely on engineering estimates of the cost to replace facilities. Where applicable, we attempt to supplement and verify the costs we use with current construction estimates and other available data. In developing our RCN value, we rely on the following key assumptions:

- Brownfield construction[1]
- A single unit cost for overhead conductor regardless of circuit size
- A single unit cost for underground conductor regardless of circuit size
- The cost of primary pole risers are included with underground conductors
- Materials and labor prices from PG&E's Job Estimating Tool (JET)
- The number of meters are set equal to the number of electric customers (accounts) served in the area
- The number of underground services are set equal to 35 percent of services recognizing among other factors the circuit length of underground versus overhead feeders

In Table 1.0 (Column B), we summarize our determination of RCN as of December 31, 2004. As shown in this table, RCN as of the end of 2004 amounts to $439.25 million. This amount represents the cost of constructing today in new condition PG&E's property SMUD proposes to condemn in the original area.

[1] Brownfield construction assumes, consistent with the alternatives available to SMUD of constructing a new system today, in the area SMUD is considering condemning, that construction will encounter obstacles in place such as streets, landscaping, other utility services, etc.

Table 1.0
Pacific Gas and Electric Company
Property SMUD Proposes to Condemn
Original Condemnation Area
Fair Market Value as of January 1, 2008
Summary

Line No.	[A] Description - Units	[B] As of 12/31/2004 RCN	[C] As of 12/31/2004 RCNLD	[D] As of 1/1/2008 RCN	[E] As of 1/1/2008 RCNLD
		$ million	$ million	$ million	$ million
	Plant in Service as of 12/31/04				
1	Transmission Plant				
2	Rights of Way	7.50	7.50	7.96	7.96
3	Transmission	34.00	22.09	33.59	20.89
4	Total Transmission	41.50	29.59	41.55	28.85
5	Distribution Plant				
6	Rights of Way	16.10	16.10	17.09	17.09
7	Substations	36.64	26.40	36.34	25.64
8	Overhead Feeders	40.44	28.28	39.71	26.98
9	Underground Feeders	184.89	153.52	192.45	151.77
10	Transformers	32.13	22.40	31.35	20.94
11	Low Voltage Circuits	6.54	4.82	6.77	4.52
12	Overhead Services	12.60	10.00	12.78	9.87
13	Underground Services	24.75	21.84	26.18	22.09
14	Meters	7.34	5.26	7.46	4.92
15	Miscellaneous Equipment	36.32	27.16	36.83	25.91
16	Total Distribution	397.75	315.79	406.96	309.71
17	RCN 12/31/04 Plant	439.25	345.38	448.51	338.57
18	Additions 2005, 2006 , & 2007			45.07	44.09
19	RCN 1/1/08 Plant			493.58	382.66
20	Going Concern Value @ 25%				123.39
21	Other Assets				20.50
22	Liabilities				(11.11)
23	Fair Market Value as of 1/1/08				515.44
24	Stranded Investment				36.32
25	Severance				14.12
26	Total				565.88

1.5 Replacement Cost New Less Depreciation

While today's cost to construct the property amounts to $439.25 million, the actual property SMUD desires to condemn is not new but has been in use for some time providing service to PG&E customers. Since the property to be acquired is not new, we reduce its RCN value for depreciation. Depreciation represents loss in service value not restored by current maintenance associated with the consumption of assets due to physical, economic, and other factors. For a property unit depreciation represents the difference between the present worth of its benefits over its remaining life and the present worth of the benefits a new property would produce over its life. In connection with the valuation of utility and other assets, we routinely rely on observed condition and statistical approaches at asses depreciation. For this report, we have not conducted the detailed inspections necessary to reach any definitive conclusion about condition. We do however note that nothing has come to our attention (including during the course of the field inspections) that suggests the condition of the assets does not generally correspond to the condition expected of similar property of comparable age.

In lieu of observed condition, we rely on general patterns of property retirements predicted based on the average service lives and mortality patterns PG&E uses to develop its accounting depreciation rates. For the purpose of this report, we have not confirmed the reasonableness of these service lives and curve shapes for use in valuing the subject property. However, based on our experience, they appear reasonable, though overall we believe that the service lives we use are generally less than the level a detailed study of the specific property will indicate. To the extent that the service lives used for depreciation purposes are understated, our resultant fair market value is also understated.

In developing our deduction for depreciation, we rely on the condition percent determined for group properties as defined by the service lives and mortality patterns and age of the various properties. In developing our condition, we endeavor to distribute value equitably between the buyer and seller. Recognizing that both Beck and Staff suggest that SMUD would finance an acquisition by issuing taxable revenue bonds, we have developed our allowance for depreciation incorporating a 6.25 percent interest factor.

As shown in Table 1.0 (Column C) we find that RCNLD for the subject property as of December 31, 2004 amounts to $345.38 million.

1.6 RCNLD As of January 1, 2008

In this report, we measure the value of PG&E property in the original area SMUD proposes to condemn. If SMUD indeed condemns the property, we estimate that at the earliest, SMUD will not be able to take title prior to January 1, 2008.[2] To properly recognize the timing of any condemnation, we adjust our December 31, 2004 RCNLD value to conditions expected as of January 1, 2008.

In this regard, in Table 1.0 we summarize RCN and RCNLD of PG&E's December 31, 2004 plant as of January 1, 2008 (Columns D and E). To develop RCN as of January 1, 2008, we increase December 31, 2004 RCN to reflect cost level increases of 2 percent per year and reduce RCN to reflect three years' expected retirements. We forecast retirements using the same survivor curves and average service lives we use to develop condition in our RCNLD. We show in Table 1.0, Line 17, Column D, $448.51 million as the RCN value for the December 2004 plant as of the first of 2008.

To develop RCNLD, we adjust our RCNLD value as of December 31, 2004 by the above and to reflect the reduced condition resulting from a 3-year increase in age. We show in Table 1.0, RCNLD for the December 31, 2004 plant as of the first of 2008 of $338.57 million.

PG&E will make certain capital improvements in the original area during the three year period from December 31, 2004 to January 1, 2008. These capital additions include:

1. Facilities to serve new customers in the area
2. Additions and upgrades to enhance reliability
3. Additions to distribution system including emergency responses
4. Distribution preventative maintenance
5. Planned undergrounding of existing overhead distribution lines (rule 20A)
6. Relocations and rearrangements for third parties
7. Planned transmission line capacity projects

Capital additions during the three-year period total $43.57 million. As shown in Table 1.0, after inflation, 2008 RCN amounts to $45.07 million. After depreciation, their RCNLD value as of January 1, 2008 amounts to $44.09 million.

As shown on Line 19 of Table 1.0, of the facilities under consideration total RCN amounts to $493.58 million and total RCNLD amounts to $382.66 million as of January 1, 2008. Assuming that cost level increases and capital additions during the 9 month period beginning January 1, 2008 continue at the same rate as the previous three years, as of October 1, 2008 RCN amounts to $506.41 million and RCNLD amounts to $392.60 million.

[2] In SMUD's application to LAFCo, SMUD estimates October 2008. SMUD's timetable does not propose to even begin pretrial eminent domain proceedings until after a November 2006 annexation vote.

1.7 Additional Elements of Value

In addition to the depreciated cost of replacing the specific original area assets SMUD proposes to condemn, there are certain additional considerations, which add and subtract from RCNLD to determine fair market value. RCNLD measures the value of a given set of assets; it does not include the additional value of a viable business enterprise wherein customers are attached, taking service, and paying for service.

The courts have long held that the condemnation of utility property (such as contemplated by SMUD) involves much more than the taking of physical assets. SMUD intends to condemn the property in order to access the customer base. More than merely taking the property, SMUD intends to take the business resulting from the assembly, ownership, and operation of the property. Because SMUD intends to take the business, courts have held that the buyer should compensate the owner for the value incident to operating a viable business. Courts typically refer to this increment of value as going concern value.[3]

Going concern value involves consideration of a number of factors. Typically, going concern allowances include 1) the costs incurred by the owner to attract and attach the customers being served, 2) the fixed and operating costs incurred by the owner for plant in service prior to attaching existing customers, 3) the costs and value of maps and records associated with the property taken and the customers acquired, and 4) the value attributed to use or potential use of the facilities for business purposes other than providing electric utility service. For example, among others, the potential for net revenues associated with using the facilities to provide BPL (broadband over power line) service and for automated realtime metering adds value, as do the net revenues already realized by PG&E through the leasing of space on and under its transmission towers to PCS carriers (digital wireless service), and the value of PG&E's fiber optic lines. These communications related elements (BPL, AMI, and fiber) not only provide potential value as a result of additional revenue streams, they offer the potential to reduce cost, enhance customer service, and add service offerings through real time remote metering, and two way communication capability. Including a value for the facilities' actual and potential use to deliver services in addition to electric power is consistent with California's requirement that the fair market value PG&E receive reflect "full knowledge of all the uses and purposes for which the property is reasonably adaptable and available" (Cal. Code of Civ. Proc. §1263.320(a).) To reflect this additional value, we include an allowance of 25 percent of RCN as going concern value. We base this allowance on our

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[3] Brunswick RT. Water Dist. V. Marine Water Co., 59A.537. (Me. 1904)

experience, consideration of the above, and allowances found reasonable in the past by courts.[4]

Also incident to a taking of PG&E's property are certain short term assets for which SMUD should compensate PG&E. These short-term assets include accounts receivable and unbilled revenues for service PG&E has provided to customers but for which the customers have not yet paid. Short-term assets also include construction work in progress (CWIP). CWIP represents investment PG&E has made in improvements, which are not included in the RCNLD value. Typically, in connection with the taking of utility property the buyer compensates the seller for outstanding balances for these items (as well as, capital additions placed in service by the seller from the date of valuation) on the date the sale is completed. We understand California law is in accord.

The final item relates to liabilities incident to the sale. We are unaware of any liabilities associated with the sale of PG&E's property in the original area SMUD proposes to condemn. However, in the event SMUD takes the property, SMUD assumes the liability associated with the cost of removing facilities upon their ultimate retirement. This cost of removal will be reduced by any salvage realized. We adjust value to reflect the present worth of this potential liability. We develop this adjustment using a 6.25 percent present worth factor, the probable lives of the facilities, and net salvage values underlying PG&E's depreciation expense rates.

As shown in Table 1.0, after consideration of these additional elements of value, we find $515.44 million as the fair market value of PG&E's transmission and distribution properties in the original area SMUD proposes to condemn as of January 1, 2008. Extending this to October 1, 2008, we find the fair market value as of October 1, 2008 to be $528.84 million.

1.8 Stranded Investment / Severance

In addition to the fair market value of the property taken, PG&E will be entitled to compensation for the decline in value suffered by facilities that become stranded or otherwise adversely affected as a result of the taking. Stranded investment relates primarily to transmission lines that PG&E relies on to serve the area proposed to be condemned which will no longer be required by PG&E to serve customers, as well as excess capacity PG&E will have in its Brighton Substation as a result of the taking.

As shown in Table 9.4.1.1, PG&E has preliminarily identified 61.59 circuit miles of its transmission lines which will no longer be of use to serve PG&E's remaining customers

[4] See Nichols on Eminent Domain (14A-14)

if the original area proposed to be condemned is taken by SMUD. The RCN associated with these lines amounts to $39.16 million with an associated RCNLD of $27.84 million.

In addition to the transmission lines stranded, PG&E will no longer need the entire 533 MVA of capacity at its Brighton substation. If SMUD succeeds in taking PG&E's property in the original area, PG&E will no longer need the 420 MVA transformer at the Brighton substation which was installed in 2004 at a cost of $8.0 million. The RCNLD values as of January 1, 2008 associated with this transformer amounts to $8.48 million.

Based on the foregoing we find the total RCNLD value of stranded investment as of January 1, 2008 to amount to $36.32 million. In addition to the transmission and substation investment stranded, if SMUD condemns facilities in the area proposed, power flows in the Sacramento area will change. As a result of these changes, certain transmission system reinforcements will be required. PG&E is entitled to be compensated for the costs of making these system reinforcements. Based on estimates of the costs and timing of needed reinforcements, PG&E is entitled to $14.12 million (as of January 1, 2008) in severance damages based on the implication of SMUD's plan.

We find the total fair market value of PG&E's facilities including an allowance for stranded investment and severance as of January 1, 2008 to amount to $565.88. As of October 1, 2008 we estimate this will increase to $580.60 million.

1.9 Key Differences in Value between Beck, Staff, and B&V

The value of PG&E's electric utility property in the original area SMUD proposes to condemn set forth in this report is one of three different values estimated to date for this property. The differences are quite substantial. While the difference between Staff's value of $130 million exceeds Beck's value of $102 million by about 27 percent, our value of $515.44 million (excluding stranded investment) exceeds Staff's by 300 percent.

In Table 1.9.1 we summarize our reconciliation of these three values. In Tables 8.1 and 8.2,[5] we reconcile these values in a different fashion.

1.9.1 Beck and Staff

As shown in Table 1.9.1, the difference between Beck's and Staff's values relates to three principal factors. These factors are Beck's much lower unit cost of underground feeders and Beck's failure to include any allowance for the value of underground services, offset by Beck's proposed condemnation of 138 miles of transmission lines, versus Staff's 91.82 miles.

[5] See Tables 9.8.1.1, 9.8.1.2, 9.8.2.1, and 9.8.2.2 for additional detail.

Beck's failure to include any allowance for value associated with underground services leads us to question the study's overall credibility. Beck includes <u>no</u> underground services notwithstanding finding 260 miles[6] of underground feeders. We question the credibility of any study which claims there are no underground services in an area the size of the original area SMUD proposes to condemn, much less one that assumes there are 260 circuit miles of underground distribution lines and 70,000 customers.

Table 1.9.1
Pacific Gas and Electric Company
Reconciliation of Fair Market Value
Original Condemnation Area
Beck, Staff, and B&V

	[A]	[B]	[C]
Line No.	Description	RCN	RCNLD
		$ million	$ million
1	Beck	200.93	102.14
2	Reconciliation of Beck to Staff		
3	Transmission Lines	(22.96)	
4	Substations	(9.07)	
5	Unit Cost of UG Feeders	42.02	
6	Underground Services	24.18	
7	Other (Balance)	10.20	
8	Staff	245.30	130.34
9	Reconciliation of Staff to B&V		
10	Transmission Lines	2.29	
11	Substations	18.90	
12	Rights of Way	15.54	
13	Underground Distribution	114.83	
14	Transformers	14.78	
15	Miscellaneous	26.30	
16	Other (Balance)	1.32	
17	Total B&V as of 12/31/04 before other elements of Value	439.25	345.38
18	Other Elements of RCNLD overlooked by Beck and Staff		
19	Change in Value 12/31/04 to 1/1/08	9.25	(6.82)
20	Additions 2005, 2006, & 2007	45.07	44.09
21	Total B&V RCNLD as of 1/1/08	493.58	382.66
22	Other Elements of value overlooked by Beck and Staff		
23	Going Concern Value @ 25%		123.39
24	Other Assets		20.50
25	Liabilities (Net Salvage)		(11.11)
26	Total Fair Market Value as of 1/1/08		515.44

[6] We will subsequently demonstrate that Beck understates PG&E's underground lines by about 25 percent.

Furthermore, while Beck fails to include any allowance for underground services, it includes allowances for about 41,000 overhead services and meters. Based on PG&E's records, PG&E serves about 70,000 electric customers in the original area. Typically, we expect a utility has a few more meters than customers, and about the same number of services as customers. Again, we question the credibility of Beck's study. How much can one rely on a study in which over 40 percent of the services (customers) are missed, especially a study supposedly based on a detailed system inspection as claimed by Beck?

The credibility of Beck's conclusions can be further questioned when we recognize that not only does Beck fail to include the value of about 30,000 services and meters, it shows in Table 1-32 that indeed it actually estimated 72,300 customers in the original area.

Beck's allowance for underground feeders is based on a unit cost of about $108,000 per mile. This unit cost is 60 percent below Staff's unit cost of about $270,000 per mile. We will address these unit costs in our subsequent discussion regarding trenching and paving.

Beck has included in its valuation the cost associated with over 130 miles of transmission lines whereas Staff suggests condemning about 92 circuit miles (including 18.82 stranded). Staff suggests that its proposal requires SMUD to acquire fewer lines from PG&E and reduces the lines stranded as a result of the taking but requires SMUD to construct some additional lines. While Staff suggests that only 10.66 miles (18.82 circuit miles) are stranded under its suggestion, in reality Staff's proposal leaves 61.78 circuit miles stranded. See table 9.4.1.1 for a reconciliation of Staff's transmission lines with our determination of the transmission lines affected by its proposal.

1.9.2 Staff and B&V

As shown in Table 1.9.1, we identify 6 factors which account for the difference between Staff's $245 million RCN value and our value of $439.25 million (RCN as of December 31, 2004). As we show, $114.83 million (59 percent) of this difference relates to underground distribution.[7] This $114.83 million difference embodies two deficiencies in the Staff's (and Beck's) RCN value.

First, Staff assumes that PG&E has 259 circuit miles of underground distribution feeders in the area. This 259-mile figure approximates the 260-mile figure developed by Beck. Based on our detailed studies, we find that PG&E has at least 354 miles of underground feeders in the original area SMUD proposes to condemn. Of Staff's (and Beck's) $114.83 million understatement, over $25 million relates to their failure to include

[7] This difference is relative to Staff. The difference in RCN between our RCN value and Beck's includes this amount <u>plus an additional $42 million attributable to the lower unit cost of underground feeders below Staff's insufficient level.</u>

consideration of over 25 percent of the actual underground distribution system. In light of Beck's failure to identify any underground services, its failure to recognize the extent of PG&E's underground system is not surprising.

By far the single biggest difference between our RCN value and the Beck/Staff values is their failure to consider the cost of placing underground equipment underground. This oversight amounts to nearly $90 million. Cost-based measures of value measure value based on the cost to build a competing system because that is the condemner's alternative to condemnation. Clearly if SMUD were to construct facilities in the area, SMUD would place underground facilities underground and would incur the cost of doing so.

The overall reasonableness of the unit cost of underground lines is verified by comparing our unit cost of $523,000 per mile ($273,000 conductor plus $250,000 conduit and trenching) with other information. In this regard, we find that in a March 2005 study prepared by Navigant Consulting, Inc. for the Long Island Power Authority, Navigant estimated the costs of underground construction at ten times the cost of overhead, and for utilities the costs range from $765,000 per mile to $1,826,000 per mile. Our allowance of $523,000 per mile certainly appears reasonable in light of the Navigant Report. Our unit cost of underground exceeds our unit cost of overhead by a factor of 7.3 times which falls below the norm of ten identified by Navigant. Our unit cost is clearly reasonable.

Other major differences between the cost levels reflected by Staff and those set forth herein relate to:

- Transmission Lines – Staff fails to properly quantify the transmission lines it proposes to condemn and understates the costs of the lines primarily due to its failure to allow for the costs of major towers required to support high voltage lines over certain river and other crossings.
- Substations – Staff fails to include allowance for equipment it proposes to condemn as well as understating the value of equipment it does include. Staff's failure especially relates to PG&E's West Sacramento substation.
- Distribution Rights of Way – Staff fails to include in its analysis the value of most of PG&E's 2,300 parcels in the original area under consideration.
- Transformers – Staff significantly understates the quantity and capacity of the line transformers required to serve customers in the area it proposes to condemn.

- Miscellaneous Equipment – Staff does not include various fuses and junction boxes in its inventory and understates the unit cost of various switches, reclosers, and capacitors required to serve customers in the area proposed to be condemned.

In short, due to various errors and omissions, neither Beck's nor Staff's determination of RCN can be used as a realistic measure of the current cost to replace PG&E's property required to serve customers in the area.

1.9.3 Depreciation

Differences in RCN flow through to RCNLD. However, differences in RCNLD also reflect differences in depreciation. Beck and Staff estimate that the overall condition[8] of PG&E's facilities is 51 and 53 percent respectively. We find the overall condition percent approaches 80 percent. The difference in condition relates to two principal factors. First, Beck and Staff both adjust condition (depreciation) to reflect net salvage (gross salvage revenues less cost of removal). However, both Beck and Staff improperly calculate the effect of net salvage on fair market value in two respects. First, they develop the amount of net salvage improperly. The net salvage allowance they use is the net salvage allowance percentage included in PG&E's depreciation rates. Beck and Staff apply these net salvage percentages to replacement cost new. This treatment significantly overstates net salvage because the net salvage percentages included in PG&E's depreciation rates are based on original cost, not RCN. The percentages included in depreciation rates when applied to original cost produce an estimate of net salvage cost that will be incurred when the property is retired. Applying them to RCN overstates salvage cost.

The second factor relates to the timing of net salvage. Beck and Staff develop their adjustment for net salvage as if SMUD will incur this cost[9] upon takeover. In fact, SMUD will not expend these funds until plant is retired. The effect of net salvage on fair market value is the present worth, as of the valuation date, of the net salvage cost expected to be incurred in the future when the property is retired.

In addition to their error in calculating the effect of net salvage on value, neither Beck nor Staff properly recognize that the value of condemned property is a function of the time that the property will remain in service and the time value of money. The value today that a piece of property contributes during the first 10 years of its life exceeds today's value that that same piece of property contributes during the second 10 years of its life.

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[8] Condition percent represents the portion of original value remaining at a point in time. Condition percent is equal to 1 minus the percent depreciated.
[9] Generally cost of removal exceeds gross salvage revenue to produce negative net salvage.

In order to capture this timing we include in our depreciation calculation the implication of the cost of money. Beck and Staff both assume that the cost of money is equal to zero, an obvious erroneous assumption.

1.9.4 Valuation Date

In the above, we address differences between Beck's, Staff's, and our RCN and RCNLD values as of December 31, 2004. As we show in Table 1.9.1, our RCNLD value amounts to $515.44 million compared to Beck's $102 million and Staff's $130 million. Beck's and Staff's RCNLD values can not be relied on because of flaws including:

1. Failure to include the cost (value) of placing underground equipment underground.
2. Failure to include the cost (value) of a substantial portion of PG&E's equipment SMUD proposes to condemn.
3. Failure to include the cost (value) of rights of way needed to access the equipment SMUD proposes to condemn.
4. Improper reduction in value due to errors in the determination of net salvage and using a zero interest rate.

In addition to these <u>flaws</u> in Beck's and Staff's development of RCNLD as of December 31, 2004, they further understate fair market value by over $170 million by failing to consider:

1. Changes in value and capital additions that will occur prior to a taking by SMUD (See Section 5.0).
2. Going concern value (See Section 6.0).
3. Other assets taken (See Section 7.0).

2.0 Introduction and Qualifications

The Sacramento Municipal Utility District's (SMUD) Board is pursuing condemnation of the electric utility service areas currently served by the Pacific Gas and Electric Company (PG&E) in the Cities of Davis, West Sacramento, and Woodland, California as well as some unincorporated areas of Yolo County, California.

By letter dated July 17, 2005, the Sacramento Local Agency Formation Commission (LAFCo) informed PG&E of an expected application from SMUD proposing to annex this territory and requesting certain data of PG&E.[10]

R. W. Beck (Beck), in a January 2005 report, provided estimates of the value of PG&E's facilities in the area under consideration. In response to Beck's estimate, PG&E prepared an estimate of the value of the facilities. The value estimated by Beck is considerably lower than the value determined by PG&E[11]. Subsequently, the SMUD Staff (Staff) prepared an estimate of value in excess of the estimate prepared by Beck, but still considerably less than PG&E's estimate. The SMUD Board apparently relied on the Beck and Staff valuations in deciding to pursue condemnation.

We understand that PG&E does not want to sell its electric utility system properties in Yolo County. Therefore, in order for SMUD to take these properties, it must ultimately pursue an action in eminent domain (condemnation).

2.1 Purpose

The purpose of this report is to describe the detailed analysis underlying Black & Veatch's independent determination of the fair market value of the facilities under consideration. Since PG&E has repeatedly stated that these properties are not for sale, we determine value based on consideration of their fair market value consistent with statutory requirements and case law in connection with the condemnation of utility property. The detailed information set forth in this report and its appendices also serves as the response to much of the information related to value requested in LAFCo's June 17, 2005 letter to PG&E. In addition, because the value determined herein is substantially higher than the estimates provided by Beck and Staff, we compare the various estimates and describe some of the omissions and inaccuracies in the Beck and Staff estimates.

[10] SMUD submitted its application July 29, 2005.
[11] Black & Veatch assisted PG&E in developing this preliminary estimate.

2.2 Scope

In this report, we limit our analysis to the determination of fair market value consistent with the standards required in the condemnation of utility properties in California. We limit our analysis to the facilities specified in the "map of the proposal territory" attached to the June 17, 2005 letter to Mr. Thomas E. Bottorff (PG&E) from Mr. Peter Brundage (LAFCo). We include a copy of this map as Figure 4.1.1.

We include in the report:

- A discussion of the general approaches used to measure value
- A discussion of the general nature of electric utility properties
- A description of the approach we follow to determine the property PG&E uses to provide utility service in the area at issue (inventory)
- A description of the approach we follow to determine the current unit cost (replacement cost new - RCN) of the property at issue
- A description of the approach we follow to adjust the property's value to reflect its existing condition relative to new (condition percent)
- A detailed description of our determination of replacement cost new less depreciation (RCNLD) for the various elements of property at issue
- A discussion of the capital additions PG&E forecasts to add between the end of 2004 and January 1, 2008
- A discussion of the change in value forecast for property in the area between December 31, 2004 and January 1, 2008
- A discussion of the additional value the facilities possess as a going concern
- A summary of our determination of the total value of the facilities at issue as of January 1, 2008, including consideration of other assets and liabilities
- A summary of our determination of the total fair market value of the facilities at issue as of October 1, 2008, the date SMUD identifies in its application to LAFCo as the estimated date of a take over
- A summary of the fair market value of PG&E facilities which would be stranded and no longer of value to PG&E if SMUD succeeds in taking the PG&E facilities it proposes to condemn
- A critique of the estimates of value prepared by Beck and Staff

We include as appendices detailed analyses and data we rely on in preparing our estimate.

In this report, we do not address severance damages except to the extent needed to explain our determination of the value of the assets SMUD is attempting to acquire and assets stranded upon a taking by SMUD.[12] We also do not address financing, litigation and other costs SMUD would incur to acquire the assets through eminent domain.

2.3 Qualifications

Black & Veatch is a leading global consulting, engineering, and construction company specializing in infrastructure and infrastructure development. With a staff of over 6,000, Black & Veatch provides valuation, utility feasibility studies, financial management, asset management, information technology, environmental and management consulting services, conceptual and preliminary engineering services, engineering design, procurement, and construction. The company was founded in 1915 and maintains more than 90 offices worldwide including offices in Sacramento and Concord, California. Black & Veatch is headquartered in Kansas City, Missouri and was ranked 92nd on the *Forbes* "500 Top Private Companies in the U.S." listing for 2003.

Our client base includes investor owned, publicly owned, and cooperatively owned utilities, customers of such utilities, as well as, other entities involved in the energy, water and wastewater industries, and government agencies.

[12] In its LAFCo application, SMUD introduces uncertainty with regard to the facilities it desires to condemn. The area identified by SMUD differs substantially from the area identified by Beck and Staff. To date, we are unaware of any estimate of value, or of the economic consequences of SMUD taking the area it identifies in its LAFCo application. For the purpose of this report, we develop fair market value for the service area and facilities identified by Beck and Staff, the "original area proposed to be condemned."

3.0 Value of Electric Utility Property

3.1 Value

3.1.1 Definition

PG&E counsel informs us that SMUD's taking of PG&E's property is governed by California Eminent Domain Law. That law requires SMUD to pay PG&E "fair market value of the property taken" (Cal. Code of Civil Procedures §1263.310). "Fair market value" is

> "the *highest price* on the date of valuation that would be agreed to by a seller, being willing to sell but under no particular or urgent necessity for so doing, nor obliged to sell, and a buyer, being ready, willing, and able to buy but under no particular necessity for so doing, each dealing with the other with full knowledge of all the uses and purposes for which the property is reasonably adaptable and available" (Id. §126.320(a); emphasis added).

Valuation experts tend to agree on definitions of value consistent with the quoted California law. Experts however often disagree about the appropriate valuation approach to value a particular asset and the assumptions and elements that underlie a reasonable determination of value.

With the above definition in mind, we are further guided in this report by the goal of valuing property in eminent domain as stated in *Nichols on Eminent Domain (14A-8)*:

> "The constitutional goal of valuation in eminent domain is just or full compensation, a 'practical attempt to make the owner whole.' It is an effort to put the owner in as good a position financially as he or she would have been, but for the taking.[1]

[1] Jacksonville Expressway Auth. V. Henry G. Dupree Co., 108 So. 2d 289 (Fla. 1958).

3.1.2 Approaches

Valuation experts tend to agree that there are three general methods to measure value. These are market based, earnings based, and cost based.

Market Based

Market-based approaches measure value based on the prices paid for properties that are comparable to the property being valued. Thus, they measure value from the perspective of alternative assets available for the buyer to purchase which provide the same functional utility. Because of differences between assets actually sold and the assets being valued, the analyst must usually make adjustments to reflect such differences.

Typically, market-based measures of value do not produce reliable results for utility property. For utility property, there are a limited number of transactions of comparable properties, especially in the number of transactions, which meet the “willing buyer-willing seller” test.

In connection with the sale of privately owned utility property (such as PG&E’s), the seller may be compelled to sell, due to the threat of condemnation, unfavorable regulatory treatment, and other potential barriers to the economic (and profitable) operation of the property. Likewise, when considering sales of either investor-owned or publicly owned property, equal care must be taken to insure the sale is not “distressed” due to the utility owner’s financial condition or anticipated regulatory expenses, which can distort the motivations and depress the sales price. A further factor that the analyst must consider (but often does not because of a lack of knowledge) is the effect on the sale price of non-cash and/or deferred compensation.

In developing fair market value for the purpose of this report, we were unable to identify any transactions involving substantially similar properties that meet the “willing buyer-willing seller” standard. We did not develop value based on consideration of market-based measures. Neither Beck nor Staff investigated the value of the area SMUD proposes to condemn based on marked-based measures.

Earnings Based

The focus of earnings-based approaches is the earnings capability of the asset. Thus, earnings-based approaches measure value from the perspective of alternative investments available to the buyer or seller, which provide a comparable risk-adjusted return. The earnings-based value of an asset is measured based on the forecasted discounted cash flow associated with the ownership (and/or operation, as applicable) of the asset. Analysts often simplify the discounted cash flow approach by use of a capitalized earnings approach.

Though earnings-based measures of value are particularly applicable to business property, the application of earnings-based measures to rate-regulated utility property seldom produces reliable results. In *Natural Gas Pipeline*, the United States Supreme Court[13] observed that “rates affect value and value affects rates.” In that case, the court

[13] Federal Power Commission v. Natural Gas Pipeline Co. of America. 315 U.S. 575, 62S.Ct.736, 86 L.Ed. 1037 (1942).

authorized abandoning the "fair value standard"[14] for rate setting cutting the circular effect of rates affecting value and value affecting rates. Application of earnings-based measures of value to rate regulated (utility) property reintroduces this circularity by producing a value approximately equal to rate base. In connection with condemnation matters, the courts have recognized that earnings-based measures, while generally applicable in valuing non-rate-regulated business enterprises, may **not** be appropriate for use in connection with valuing utility property.

The inappropriateness of relying on the income approach is evidenced by the income analysis prepared by Beck. Beck's income approach assumes system revenues are limited to PG&E's CPUC-regulated rates, when SMUD's rates will not be regulated. Further Beck fails to consider other revenues the facilities already do and potentially can generate in excess of the present regulated revenues. Regulated rates are based on an Original Cost Less Depreciation (OCLD) rate base, so the income approach as Beck applied it is simply a back-door method of valuing on the basis of OCLD. The U.S. Supreme Court cases (*Natural Gas Pipeline* and *Hope*) which upheld the constitutionality of rate-regulation held that while OCLD is appropriate for rate setting, it may not be appropriate for just compensation in a condemnation action. SMUD can set its own rates and not pay income taxes, so it is almost certainly willing to pay more than the discounted income stream produced from PG&E's regulated electric rates. When SMUD was established and again when it acquired PG&E's Folsom assets, we understand it did so. So have other public agencies.

Cost Based

Cost-based approaches focus on the cost of the asset being valued. Thus, cost-based approaches measure value from the perspective of the cost to the buyer to construct an equivalent asset to the one being valued.

Generally, three cost based measures are acknowledged. These are original cost, reproduction cost new, and replacement cost new. Since condemned assets have typically been used, or a portion of their service life has been used up, cost based measures are typically adjusted to reflect depreciation.

[14] Prior to this decision, utility rates were based on the standard that investors were entitled to a reasonable return on the fair value of the property used and useful in providing utility service. The Court's Natural Gas Pipeline decision along with the Court's subsequent decision in Hope (Federal Power Commission v. Hope Natural Gas Co., 320 U.S.591.645.Ct.88 L.Ed. 333 (1944)) established a new rate-setting standard of a "fair return to the investor" ("end result doctrine") which ultimately resulted in the nearly universal use of net original cost rate base by agencies setting utility rates.

Original Cost

Original cost represents, for utility property, the cost of acquiring (or constructing) property when first devoted to public service. Except when the property is new, original cost seldom represents a reasonable alternative to the buyer, thus failing the substitution standard.

Typically, original cost represents the cost actually incurred in the original construction of a facility. This original cost includes allowances for all the costs incurred in construction such as materials, labor, equipment used in construction, labor benefits, engineering, allowance for funds used during construction, etc. Because of changes in cost levels between the time of original construction and the valuation date, original cost does not represent a reasonably viable alternative to a prospective buyer. As stated in Nichols on Eminent Domain,[15]

> "The more time that goes by, the less apt original cost is to reflect present value. See for example, *United States v. Toronto Hamilton & Buffalo Navigation Co.*[1], herein the Court stated that "[o]riginal cost is well termed the false standard of the past' where, as here, present market value in no way reflects the cost."[2] Original cost is therefore largely regarded as unsatisfactory as a measure of value in eminent domain."[3]
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> [1] 338 U.S 396, 70 S.Ct. 217, 94 L.Ed. 195 (1949); Simpson v. Shepard, 230 U.S. 352, 33 S.Ct. 729, 57 L.Ed. 1511 (1913).
>
> [2] City of Phoenix v. Consolidated Water Co., 101 Ariz. 43, 415 P.2d 866 (1966); Onondaga County Water Auth. v. New York Water Service Corp., 285 A.D. 655, 139 N.Y.S.2d 755 (4th Div. 1955).
>
> [3] Appleton Water Works Co. v. Railroad Commission of Wisconsin, 154 Wis. 121, 142 N.W. 476 (1913).

Neither original cost nor original cost less depreciation is among the explicitly-approved bases for testimony on the value of property in California (Evidence Code §§815-821). And neither is approved as the basis for the pre-condemnation offer SMUD must make to PG&E (California Government Code §7267.2), or for the appraisal on which SMUD must base any prejudgment deposit (Code Civ. Proc. §1255.010(b)). While in limited circumstances California allows nonlisted appraisal methods that are "just and equitable", (Evidence Code §823; Code Civ. Proc. §1263.320(b)), few would agree that in light of explosive increases in California's property values setting the current fair market value of real property and improvements at their years-ago original cost is just and equitable.

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[15] See Nichols on Eminent Domain (14A-20).

Reproduction and Replacement Cost

> "Because of the problems with the market approach discussed above and the potentially speculative nature of the income approach[16] the cost of reconstructing a public utility is generally held admissible in eminent domain.[17] [18]

Reproduction cost or more properly, reproduction cost new, represents the cost as of the date of valuation, of reproducing exactly the facility being valued. It represents the cost of constructing exactly the same facility as of the date of valuation as is in place using the same materials and having the same capability. Thus, reproduction cost represents the alternative to the buyer of constructing and using a facility identical to the one being valued. From a slightly different perspective, it represents the cost to the buyer of building a duplicate competing system. As such, it represents a real world alternative to the purchase of the property being valued.

Replacement cost new less depreciation (RCNLD) is a valuation method specifically approved by California statute for valuing improvements to land, such as the electric facilities here in issue (Cal. Evidence Code §820). For the purpose of this report, we develop the value of PG&E's property SMUD proposes to condemn using the RCNLD measure.

Replacement cost or more properly, replacement cost new (RCN), is similar to reproduction cost. Replacement cost new represents the cost the buyer would incur, if it elects to construct new facilities, instead of purchasing the asset being valued. Where as reproduction cost represents the cost of constructing identical facilities, replacement cost represents the cost of constructing facilities that provide the same functionality as the existing system, using today's materials. For electric utilities, it represents the cost of facilities necessary to deliver electricity to customers. For electric distribution and transmission system property, reproduction cost new and replacement cost new value are typically about the same.[19]

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[16] Dade County v. General Waterworks, 267 So. 2d 633 (Fla. 1962)
[17] See Puget Sound Power & Light Co. v. Public Utility Dist. No. 1 of Whatcom County, 123 F.2d 286 (9th Cir. 1941), *cert. denied*, Puget Sound Power & Light Co. v. Public Utility Dist. No. 1 of Whatcom County, 315 U.S. 814, 62 S.Ct. 798, 86 L.Ed. 1212 (1942); Kennebec Water Dist. v. City of Waterville, 97 Me. 185, 54 A. 6 (1902); City of Phoenix v. Consolidated Water Co., 101 Ariz. 43, 415 P.2d 866 (1966).
[18] Nichols on Eminent Domain (14A.06[2]).
[19] Regardless of the type of property, reproduction cost new less depreciation (after adjustments for functional obsolescence) and replacement cost new less depreciation do not materially differ if the adjustment for functional obsolescence is properly developed.

While generally reflecting minimum cost, replacement cost does not mean the minimum cost system. The existing system developed over time, and as a result, may include some inefficiency relative to a new system built from scratch. For example, the layout of existing feeders may not represent the layout which would result in the minimum cost. However, if this "inefficient layout" results in enhanced value, for example better reliability, reduced operating expenses, and/or increased life, this enhanced value should be reflected in the development of RCN, even if it means the replacement system is not the most economical.[20] Likewise, utility system components typically have capacity in excess of the absolute minimum required at a point in time. To the extent this added capacity provides enhanced reliability, extends equipment life, and offers the capability to handle reasonably anticipated growth, it should be included in replacement cost.

For the purpose of this report, we use replacement cost new (RCN) as the method to measure fair market value. RCN does not suffer from the deficiencies of other methods. RCN does not rely on sale transactions when a sufficient number of transactions do not exist. RCN does not rely on rate-regulated earnings. RCN does not rely on original cost that, except under isolated conditions, does not represent the current cost of construction and does not represent the cost levels at which SMUD can construct property today.

We refer to our method as replacement cost, not reproduction cost. By so doing, we focus on the value of the "benefit" provided by an element of property, not on the property itself. For electric transmission and distribution system property, reproduction cost new and replacement cost new are generally the same. While some modest increases in efficiency have occurred, equipment that is more efficient generally costs more, offsetting any major advantage in efficiency. Electric transmission and distribution equipment remains virtually unchanged. As a result, the detailed development of replacement cost new will compare favorably with a development following reproduction cost new.

Depreciation

Depreciation represents the loss in service value not replaced by current maintenance associated with the consumption of assets due to physical, economic, or other factors. In connection with reproduction and replacement cost measures, reducing cost by depreciation recognizes that the facilities are used and hence their value is less than when

[20] For example, PG&E relies on both pad mounted and subsurface line transformers and switches. We understand SMUD does not generally use subsurface equipment, preferring to use lower cost pad mounted equipment. Though fundamentally equivalent, there are advantages with subsurface equipment including aesthetics, reliability, and safety that we believe do not reasonably permit valuing subsurface as pad mounted equipment.

new. In connection with original cost measures, depreciation may or may not be deducted since original cost does not represent today's cost, but a historical one.

While valuation experts use the term depreciation, depreciation does not imply the proper focus. Depreciation represents what has been used, what is no longer there. In valuing assets, the focus should not be on what has been lost, but on what remains. When addressing "depreciation" in the context of value, we focus on the condition of the assets. We look at what remains of value. This prospective focus properly differentiates depreciation used for accounting purposes with condition (value remaining) for valuation purposes.

Going Concern Value

In addition to the value of the physical facilities (as measured using cost based measures of value such as RCNLD), utility property typically has an increment of value associated with assembling the facilities into a functioning distribution system and operating them as a going concern. When condemning utility property, the condemning entity usually intends to operate the property in essentially the same manner and for the same purpose (the provision of utility service) as the incumbent. In simple fact, when utility property is acquired through eminent domain, the condemning entity does not desire the property but the business.

For over one hundred years, courts have recognized various intangible factors in valuing utility property in connection with condemnation. Factors that courts have recognized include efficiency of the system, length of time necessary to construct a new system, and income and profits gained or lost for the utility to establish its business.[21] Recognition of these factors has been termed going concern value.

3.1.3 Other Compensable Value Elements

In order to remain whole, a utility needs to be compensated for certain other assets not included in RCNLD or going concern. These other assets include accounts receivable, construction work in progress (CWIP), and unbilled revenues.

Accounts receivable represent the dollar amount which a utility has billed its customers and reported as revenues but not yet been paid by the customer. Upon takeover of its facilities, the utility cannot effectively enforce collection of these funds. Therefore, the condemner should compensate the condemned for these receivables.

[21] See Nichols on Eminent Domain (14A-12), Kennebec Water Dist. v. City of Waterville, 97 Me, 57 A.6 (1902).

Unbilled revenues represent revenues for service provided to customers since the preceding meter reading date. Upon takeover of its facilities, a utility has no way to effectively enforce collection of such revenue. Therefore, the condemner should be compensated for the asset that is taken.

CWIP represents costs incurred in connection with the construction of capital projects that have not yet been completed and entered into inventory. CWIP may also consist of projects recently completed but not yet entered into inventory. CWIP represents a utility's actual costs of improving the system, which are not yet reflected in RCNLD.

3.2 Electric Utility Property

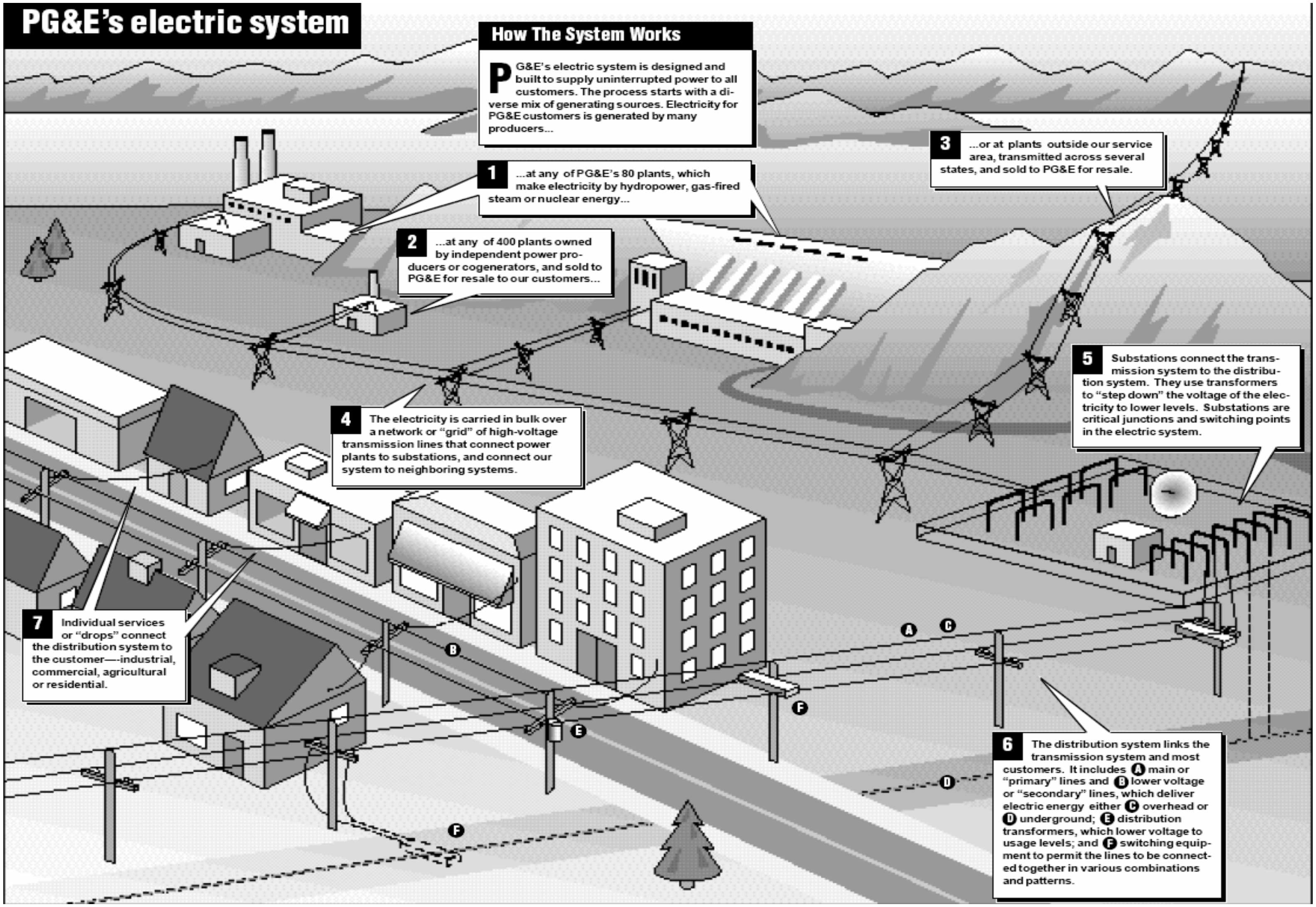
Electric power systems generally have three functional parts: power supply, transmission, and distribution. Figure 3.2 shows a simple diagram of electric system components that identifies these basic functional elements. With limited exception, all electric utility systems consist of these three functional elements. Some type of generating equipment transforms some form of energy to electric power, which is in turn transmitted through the transmission, and then distribution systems to the ultimate user. The principal exception to use of these three functional components relates to distributed generation where the conversion of energy to electric power takes place within the distribution system or on the end user's site. While there are generally three functional elements, many electric utilities do not own and operate the facilities which perform all three.

3.2.1 Power Supply

The generation of electricity is the first process in the delivery of electricity to consumers. Electric power generators use a variety of energy sources to generate electric energy. Energy sources include combustion of fossil fuels, nuclear fission, kinetic energy in water or wind, chemical energy in a fuel cell, and sunlight. Renewable energy resources such as wind, water, sunlight, geothermal energy, biomass, and waste are also used for the generation of electricity. Generating units vary in size. Nuclear and fossil-fuel steam-electric units typically have large capacities with many over 1,000 MW[22], while hydroelectric plants range from less than 1MW to thousands of MW. Combustion turbines and combined-cycle units are typically less than 500 MW. Wind and solar installations are relatively small. Distributed generation, which can be installed at or near the customer's site can be quite small, such as rooftop photovoltaic arrays or fuel cells ranging from several to a few hundred kilowatts.

[22] MW = megawatt, one million watts = 1000 kW (kilowatt).

Figure 3.2
Schematic Diagram – Electric Utility System Components



Generating units can be adjacent to customer load centers but are most often located some distance from customer load centers. A bulk power transmission system is utilized to transmit the bulk power from outlying generating stations to the local load centers.

SMUD is not considering condemning any of PG&E's power supply assets.

3.2.2 Transmission

Transmission lines transmit bulk power over long distances. Transmission lines serve to link power plants to load centers. In order to enhance reliability, transmission lines may interconnect various load centers to form an interconnected integrated system. Transmission lines typically connect two or more substations together. The transmission line is opened and closed by switching equipment located in the substation. The substation may also have transformers to step the voltage down to supply power to the distribution system.

The major components of an overhead transmission line are conductors, insulators and supporting structures. Three conductors carry electrical current thereby transmitting three-phase power. Conductors are isolated from the supporting structure and earth by insulators. Transmission line supporting structures are generally made of wood poles, steel, or aluminum. A single wood pole with wooden cross-arms may support some relatively low voltage lines (69kV[23]).

One of the major costs of transmitting power over long distances is line losses. Losses vary relative to the current flow. The same power can be delivered by increasing line voltage. Therefore, utilities use high transmission voltages to economically transmit power from remotely located generators to the load centers. This reduction in losses must be balanced against the cost of high voltage insulation for the line, as well as all equipment connected to the line (transformers, circuit breakers, surge arresters). Transmission voltages normally range from 69kV to 765kV.

Once the transmission lines reach the load centers the transmission voltage must be reduced to a level that can be safely distributed to customers. This reduction in voltage is accomplished through a substation transformer. The substation transformer reduces the transmission voltage to a distribution voltage to supply power to the distribution system.

SMUD is considering condemning certain PG&E transmission assets. These assets are located both within and outside of the original area. On the other hand, certain PG&E transmission assets physically located within the original area are not under consideration for condemnation.

[23] kV = kilovolt, one thousand volts.

3.2.3 Distribution

Distribution lines serve to transmit power within consumption areas. These lines link the transmission system to individual customers. Distribution lines (feeders) emanate from substations at voltages in the range of 4 kV to 25kV. Most distribution feeders operate at a voltage of about 12.5 kV. These distribution feeders transmit power from a distribution substation where the voltage has been stepped down from the transmission level to the distribution level. The power is transmitted through the distribution feeders to the line transformer where the voltage is stepped down to the utilization voltage, which usually ranges from 110 volts to 480 volts.

Distribution feeders can be either overhead or underground. Many newer residential and industrial areas in PG&E's service territory, including Yolo County are served by an underground system where the distribution feeders consist of insulated conductors buried underground. Typically, underground cable is installed within conduit, which is buried several feet below ground. These cables terminate at a line transformer at the ground level (referred to as pad-mounted transformers) or underground (subsurface transformers in vaults). These transformers step the voltage down to the utilization voltage. Pad mounted transformers are enclosed in a metal cabinet at ground level. The cabinet (or underground vault) may also contain switches or fuses.

In overhead distribution systems, conductors are usually uninsulated but are insulated from the supporting structure by post insulators. The conductors and post insulators are supported by a structure that usually is a wooden pole with a cross-arm. Line transformers, which step the voltage down to the utilization voltage, are mounted on the same wooden poles.

The final step of delivering power to the customer involves secondary (low voltage) lines, the service entrance,[24] and meter. The customer can be served by either a three-phase or a single-phase service entrance. Residential customers are usually served with 220 volt, single-phase power. For both underground or overhead service, an insulated cable runs from the line transformer to the customer's structure. At the customer's structure, the cable enters a meter box or metering cabinet. The meter normally divides ownership between the utility and the customer. The meter box or cabinet is usually owned by the customer.

For the purpose of this report, we assume SMUD is considering condemning all of PG&E's distribution assets within the original area proposed, but none outside the area.

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[24] Secondary lines and service lines complete the circuit path from the line transformer to the customer (meter). Typically, service lines cross the customer's property whereas secondary lies outside the customer's property.

3.2.4 General Plant

In addition to the facilities directly used to provide service to customers described above, electric utilities typically own or lease structures and equipment used indirectly. This property is usually considered "general plant" and includes such property as:

- Office buildings, furnishings, and equipment used in connection with administrative billing and collecting functions
- Vehicles
- Tools and power-operated equipment
- Service centers

We understand that SMUD is not considering condemning any of PG&E's general plant with the exception of maps and records relating to the area proposed to be taken.

4.0 Facilities Proposed for Condemnation

For the purpose of this report, we rely on the replacement cost new less depreciation (RCNLD) approach as the underlying basis to develop the fair market value of PG&E's facilities in the original area SMUD proposes to condemn. We describe in Section 3 some of the factors that lead us to use the RCNLD approach.

In developing RNCLD value, we rely on a four-step process. These steps are:

1. Develop the number and general specification of property that comprises the replacement cost system.
2. Develop the current unit cost of constructing the property elements identified in Item 1.
3. Multiply the number of property elements (Item 1) by the unit cost corresponding to that element (Item 2) to determine replacement cost new (RCN).
4. Adjust RCN to reflect condition.

4.1 Inventory

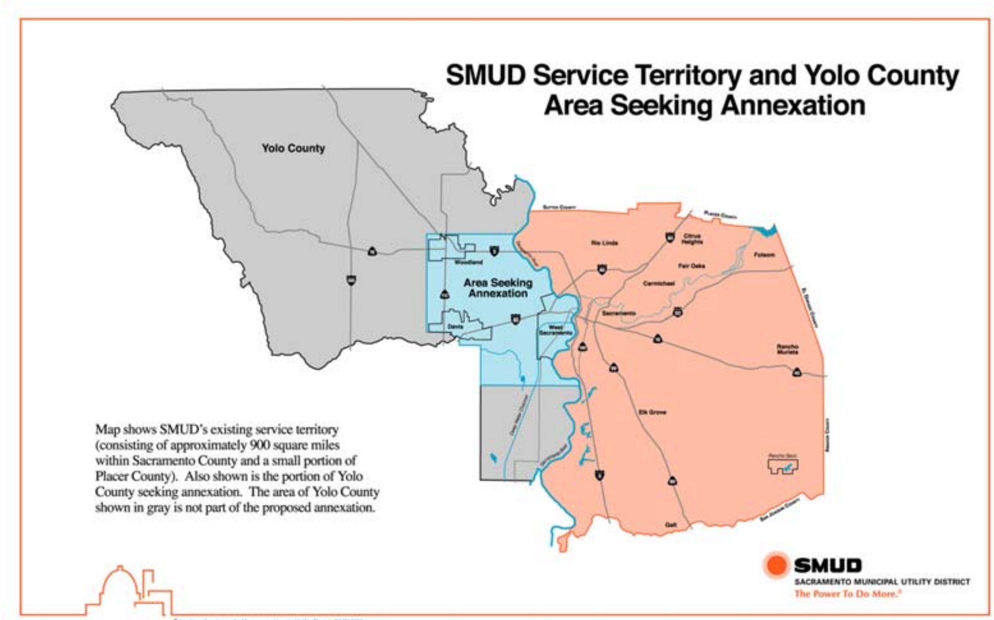
As the initial step in developing the value of the facilities under consideration, we prepare an inventory of the equipment currently in service that SMUD will need to condemn in order to provide service in the original area. In this regard, we are guided by the area shown in Figure 4.1.1 (the "original area"). The principal facilities (transmission lines and substations) within this area are shown in Figure 4.1.2. Figure 4.1.1 is a copy of the map attached to the letter dated June 17, 2005 from Mr. Peter Brundage (LAFCo) to Mr. Thomas E. Bottorff (PG&E) showing the original area under consideration.[25] The facilities included in our inventory are based on the transmission lines and distribution substations identified by Staff in its April 18, 2005 report as those SMUD wishes to take. These facilities along with other PG&E transmission lines and substations in the vicinity are highlighted in Figure 4.1.2.

[25] In SMUD's July 29, 2005 "Application for Annexation of the Cities of West Sacramento, Davis, and Woodland, and Unincorporated Areas of Yolo County and Related Sphere of Influence Amendment" submitted by SMUD to LAFCo, the area identified by SMUD differs substantially. For the purpose of this report, we address the original area since that area corresponds to the area considered by SMUD and the cities in their evaluation of the economics of condemnation. In Appendix 1, we address differences between the "original area" proposed to be condemned by Beck and Staff, and the "new area" proposed by SMUD in its July 29 application.

In Figure 4.1.2, we show PG&E's principal facilities directly impacted under the Staff's proposal. We do not show PG&E facilities that may be indirectly affected. For example, PG&E has a 500kV transmission line running north-south through the area[26]. We do not show this line in Figure 4.1.2.

Figure 4.1.1

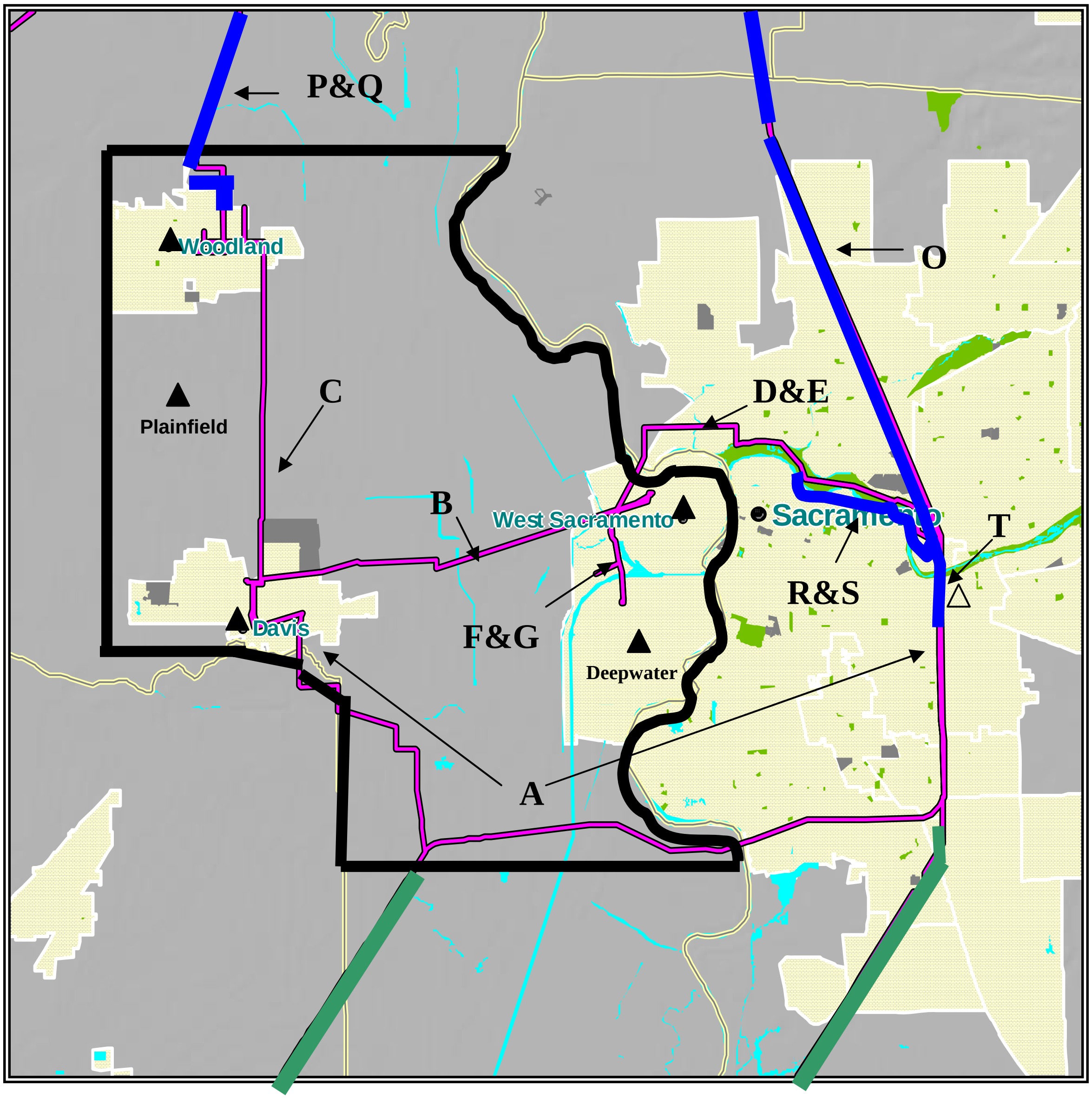
Pacific Gas and Electric Company
Service Area Under Consideration of Condemnation



As shown in Figure 4.1.2, PG&E has six (6) substations in the area shown, of which five (5) distribution substations are located in the original area and are substations SMUD proposes to condemn. The sixth station is designated as the Brighton substation and is a 230/115 KV transmission substation that SMUD does not propose to condemn. However, as we will subsequently discuss, if SMUD takes PG&E's facilities in the original area as proposed, a substantial portion of this 420 MVA substation will no longer be of value to PG&E and will therefore be stranded. We also show in Figure 4.1.2 PG&E's 115kV transmission system connecting these six substations[27]. The lines

[26] PG&E's transmission planning engineers in studying post-condemnation power flows have preliminarily concluded that the 230 kV and 500 kV lines would be adversely affected due to shifting 350+ MW of Yolo load to SMUD's transmission system. If so, recovery of any damages PG&E incurs would be appropriate.
[27] More detailed maps with respect to the transmission lines, including lateral lines serving individual customers, are included in Appendix 4.2.2.

Figure 4.1.2
Pacific Gas and Electric Company
Principal Facilities Under Consideration of Condemnation



▲ = Substations under consideration

△ = Substations not under consideration

= Transmission Lines under consideration

= Transmission Lines not under consideration (stranded)

= Transmission Lines not under consideration identified as A through G, K, L, M, P, Q, and T are lines SMUD proposes to condemn. Of these line segments, T and a portion of line segments P and Q are designated by Staff as stranded. Lines identified as J, N, O, R, and S are not lines SMUD proposes to condemn according to Staff. Line segments J and N however are required to serve customers and should have been included by Staff. Line segments O, R, and S should have been included by Staff as lines which would be stranded in the event of a taking as proposed by SMUD. In Figure 4.1.2, lines identified with a green line are not lines SMUD proposes to condemn and PG&E will continue to use them to serve its remaining customers. However, in order for PG&E to meet the needs of its remaining customers reliably, PG&E must expend substantial sums to reintegrate these lines into its system. We believe that PG&E should recover from SMUD its cost to reintegrate its system. These severance damages are beyond the scope of B&V's report.

In Table 9.4.1.1 we show a reconciliation of the transmission lines we identify with those identified by Staff. As shown in Line 18, SMUD Staff identified 77.73 linear miles (91.82 circuit miles) of transmission lines they propose to condemn. We estimate that for these lines the total circuit length amounts to 90.55 miles. We also show in this Table an additional 46.63 circuit miles Staff should have considered. We identify 137.18 circuit miles affected by the proposed condemnation of which 61.59 miles represent stranded lines.

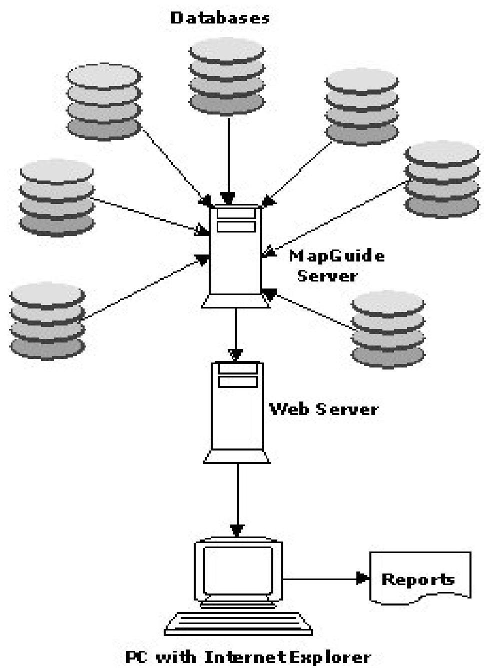
PG&E operating and planning professionals reviewed the technical aspects of PG&E's service and facilities in the area under consideration. Based on this review, and under our general direction, they developed a comprehensive inventory of PG&E's existing transmission and distribution facilities within the area, relying on actual PG&E facilities' records contained in databases and maps. The reasonableness of this inventory was subsequently verified by field inspections in selected areas.

PG&E uses a geographic information system (GIS) in the normal course of business to allow spatial visualization and to analyze the relationship between various types of equipment. Unlike a typical map which only shows spatial data (i.e., roads, cities, etc.), GIS systems link attribute data (i.e., population statistics, electric and gas transmission lines, etc.) to the spatial data in a map. We understand SMUD uses a similar system.

PG&E's Map-Guide system serves as the interface to the GIS system, allowing the user to copy and print reports (or the map view) summarizing selected attributes (miles of transmission lines, transformer kVA, installation date, etc.) shown in the current map view. PG&E professionals, including engineers, land specialists, telecom specialists, geologists, gas and electric mappers, scientists, engineers, etc. use Map-Guide in the normal course of business to access up-to-date, reliable information to use in connection with technical, scientific, and business activities.

Map-Guide is a client/server application that links multiple databases, including Geosciences, Building and Land Inventory (BLI), and Information Systems Technology Services (ISTS). The user accesses information in databases using personal computers containing the Map-Guide software through Internet Explorer. In Figure 4.1.3 we illustrate the data flow between components of Map-Guide.

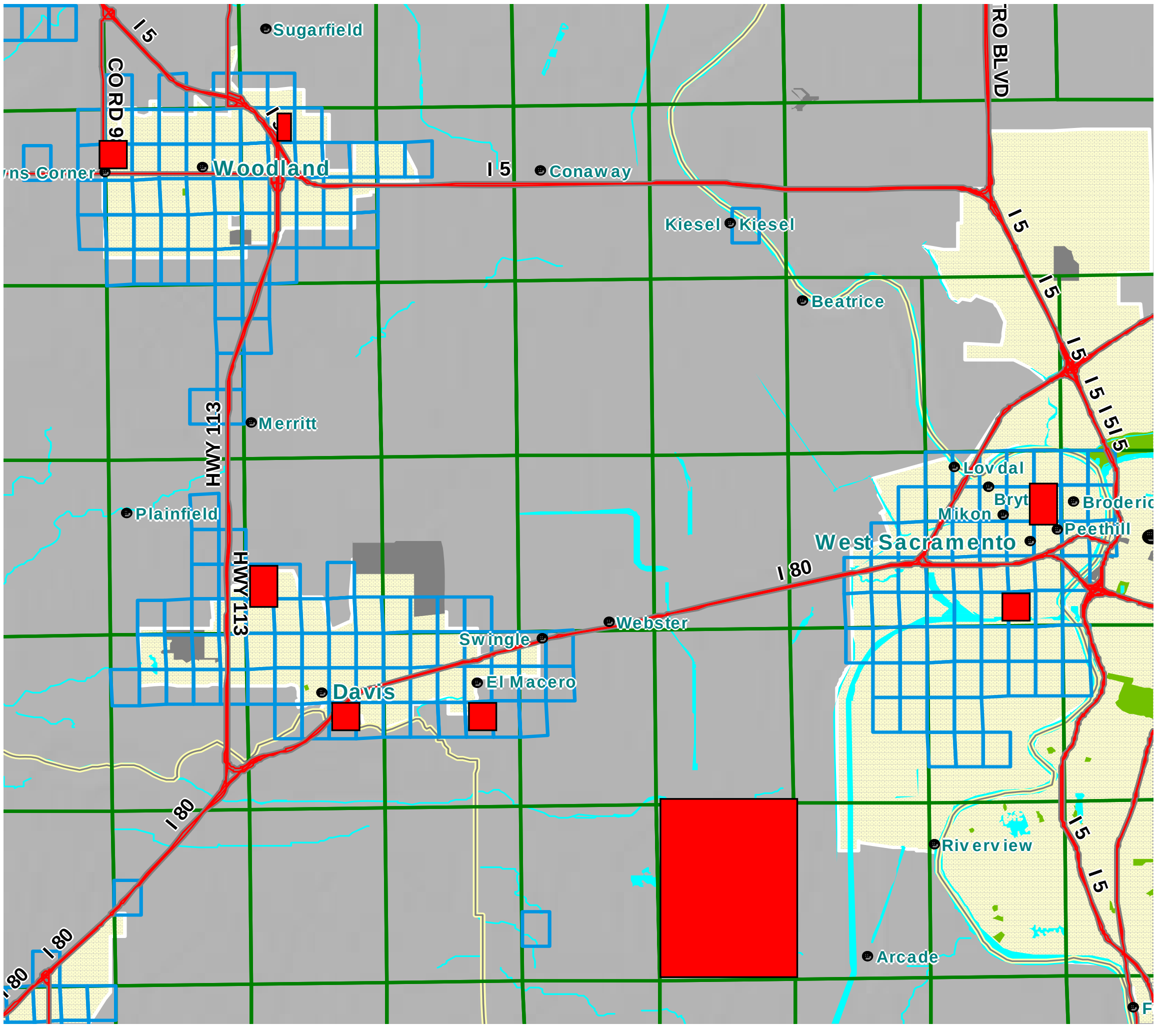
Figure 4.1.3
Map Guide Data Flow



We developed our inventory of transmission and distribution equipment in the original area using PG&E's actual databases and records. In connection with this report, we did not conduct a full field inventory. We instead rely on PG&E's databases, maps, engineering drawings, etc. However, we tested the reliability of data obtained by performing a complete field inventory of a number of areas. The individuals who performed the field inventory consisted of highly trained and skilled estimators and retired troublemen, construction supervisors, and engineers, working under the direction of experienced project managers. We looked at two groups of areas. The first group consisted of eight areas randomly selected. These areas are identified in Figure 4.1.4. The second group consist of ten areas which were not selected randomly but were intended to include areas representative of the entire original area. A map of these ten areas is included in Figure 9.4.1.1.

Figure 4.1.4

Field Inventory – Statistically Selected Locations



.Table 4.1.1
Pacific Gas and Electric Company
Comparison of Inventory in Sample Areas
Field versus Database

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Number of Units			
		CEDSA	Map	Difference	Excess %
1	OH Conductor	58,812	61,926	(3,114)	-5.0%
2	UG Conductor	50,698	59,266	(8,568)	-14.5%
3	OH Transformers	142	138	4	2.9%
4	UG Transformers	132	136	(4)	-2.9%
5	Poles	469	467	2	0.4%

The results of our selective full field inventories demonstrate the validity and completeness of the company records we rely on. In Table 4.1.1 we compare the inventory we identified in our field inventory in the randomly selected areas with what we develop from PG&E's databases. In Table 9.4.1.1 we compare the database and the field inventories in greater detail. In Appendix 4.1.1.1. we show the raw data collected during the field inspections of the eight randomly selected areas. In Table 9.4.1.3 we compare the inventory we identified in our field inventory in the ten representative areas with what we develop from PG&E's databases. In Table 9.4.1.4 we compare the database and the field inventories in greater detail. In Appendix 4.1.1.2 we show the raw data collected during the field inspections of the ten representative areas..

As demonstrated in Table 4.1.1 (and in Tables 9.4.1.2, 9.4.1.3, and 9.4.1.4) our inventory derived from PG&E's equipment records compares favorably with our field checks. Based on this comparison, we find that the inventory we developed from PG&E records is reasonably accurate for the purpose of this report. As shown overall, PG&E's records tend to understate the equipment actually in service. Some of the differences relates to new equipment which has been added to the system but has not yet been entered into the databases. Other differences relate to equipment which has been entered into databases but not yet been added to maps. To the extent this newer equipment is not included in the database, our RCNLD value is further understated due to missing the most valuable equipment. In this regard, based on field inventories, we could increase our inventory by over 10 percent in order to capture the value of equipment not reflected. For the purpose of this report, we do not so adjust, recognizing that some reduction in the actual equipment might be appropriate to recognize certain potential inefficiencies of the existing system.

As shown above, by far the largest difference relates to the length of underground conductor. This difference is consistent with wholesale shortages of underground conductor Beck develops from its computer-derived underground circuit distances

In the following, we list the data sources we use to develop the full inventory for the entire original area SMUD proposes to condemn:

- PG&E's Geographical Information System (GIS). We use this system to identify distribution circuits and plat maps associated with the proposed condemnation area as defined in Figures 4.1.1 and 4.1.2.
- Centralized Electric Distribution System Assets (C-EDSA). This database contains detailed information on PG&E's distribution circuits and equipment such as feeders, conductor, transformers, services, and miscellaneous line equipment. PG&E's Mapping Department is responsible for updating this database each time new plant is added or removed. PG&E's Electric Planning Department is the principal user of the C-EDSA database, using it for source data to model distribution circuits for necessary upgrades and additions.
- PG&E's Pole Asset Management Pole inventory database. This database contains detailed information regarding PG&E's poles and is primarily used to manage PG&E's "Test and Treat Program." We use this database to test the number of poles in the area we obtained from the C-EDSA database. As we will subsequently describe, we adjust the number of poles identified in the C-EDSA database to reflect poles not included to better reflect poles actually in service as of December 31, 2004.
- PG&E's customer records system. We use this database to accurately determine the number of customers in the area. We use the number of customers to determine the number of meters.

As described above, we use PG&E's Pole Asset Management Pole inventory database to test the number of poles we identify in the C-EDSA database. Based on this comparison, we identify a number of poles which were not included in the data we initially developed. Our initial count of poles totaled 16,546 from the C-EDSA database. We find that this count does not include 1,348 poles in the Plainfield area, 90 poles which we identified had not yet been added to the database, and 604 60KV poles with 12KV underbuild. To be conservative, we include in our pole inventory one half of these 60KV poles. Our final pole inventory amounts to 18,286 poles.

For transmission lines and substations, we primarily rely on PG&E facility engineering drawings and information obtained from PG&E field substation operation personnel.

In addition to the above sources, we consulted PG&E's Electric Planning professionals to validate information and set realistic parameters for reasonable estimates of any equipment or facilities not specifically contained in the databases normally maintained by PG&E. Some examples include distribution tap lines, which are not included in the C-EDSA database, low voltage services, and equipment used for backup.

We include the following system components in our inventory (a detailed list is included in Table 9.4.1.2):

- Transmission
  - Rights of Way
  - Lines (includes poles and towers)
- Distribution
  - Rights of Way
  - Substations
  - Overhead Lines (OH - conductors and poles)
  - Underground Lines (UG - conductor, conduit, and trenching)
  - Line Transformers (OH, pad mount, and subsurface)
  - Secondary Lines (OH and UG)
  - Service Drops (OH and UG)
  - Meters
  - Miscellaneous Equipment

The transmission system property in the proposed condemnation area is generally the same as identified by SMUD Staff. This system includes PG&E's 115kV transmission lines, which link PG&E's five distribution substations, as well as radial lines in the area. These lines are highlighted in Figure 4.1.2. In addition, transmission system property includes the rights of way obtained by PG&E to locate the lines SMUD proposes to condemn.

PG&E's distribution system properties in the area consist of the five distribution substations identified in Figure 4.1.2, the "high voltage" (12kV or 21kV) distribution feeder circuits emanating from those substations, and all equipment "down stream" of these feeder circuits (line transformers, secondary circuits, service lines, meters, and miscellaneous equipment).

4.2 Replacement Cost New

Based on the proposed condemnation area (as shown in Figure 4.1.1) and the transmission line and substations identified by Staff (see Figure 4.1.2), we first develop an inventory of equipment. As described above, we develop this inventory based on

PG&E's detailed databases of actual equipment records supplemented and verified by drawings, engineering and field professionals, and other available data. We develop RCN unit cost based on PG&E's current unit cost levels, supplemented and verified with other available data, as applicable.

We identify PG&E's distribution properties by using PG&E's GIS database to identify distribution circuits emanating from the substations identified by Staff. Based on these distribution circuits, we identify the 266 plat maps which show the location and size of PG&E's major distribution facilities in the original area. These plat maps show the location and specifics (transformer size, conductor size, etc.) for major pieces of distribution equipment including overhead and underground primary, poles, line transformers, switches, and junction boxes.

For transmission lines and substations, PG&E engineers developed detailed engineering estimates of the current cost to replace the existing equipment shown on PG&E's engineering drawings.

For distribution property, we primarily rely on unit cost developed using PG&E's Job Estimating Tool (JET). This tool is primarily used as its name implies, to estimate the cost of construction for a wide variety of construction projects. The tool is populated with current prices for materials, labor rates, and overheads. It also contains the labor hours required. PG&E designed and developed this proprietary system to assist in the valuation of assets being sold by PG&E.

Specifically, the unit costs that we rely on are based on the unit costs developed by the tool for PG&E's sale of certain assets to the Turlock Irrigation District. The unit cost developed in connection with the TID sale were adjusted using trend factors to today's cost level. Based on these units and unit costs we develop replacement cost new. The following principal assumptions underlie our determination:

- Brownfield Construction – We develop RCN assuming that construction would take place in the area as it is today, with the associated cost of construction in developed areas such as cutting and restoring pavement. We contrast brownfield construction with green field construction where construction is performed prior to development of infrastructure. Since if SMUD were to construct a competing system today, it would encounter brownfield conditions, this is the only reasonable assumption.
- Unit Cost for Overhead Conductor – We develop RCN using a single unit cost for all overhead conductor regardless of actual size. In developing the

unit cost, we endeavor to rely on the cost of the average size needed to serve customers.

- Unit Cost for Underground Conductor – We develop RCN using a single unit cost for all overhead conductor regardless of actual size. In developing the unit cost, we endeavor to rely on the cost of the average size needed to serve customers.
- Primary Pole Risers – We include the cost of risers in the cost of underground conduit (trenching). Risers are used to transition overhead to underground lines.
- Materials and labor prices – We develop material lists and labor for most distribution property (except for substations) from PG&E's development of unit cost in connection with the valuation of PG&E's assets to the Turlock Irrigation District. These cost levels were originally developed using PG&E's job estimating tool (JET). For the purpose of this report, the unit costs developed in connection with the TID sale are escalated from the July 2001 levels used in TID to today's.
- Number of meters – We identify the number of electric customers served in the area from PG&E's customer accounting system. Because of the one to one relationship between customers and meters, we set the number of meters equal to the number of electric accounts served in the original area SMUD proposes to condemn. PG&E does not maintain databases of detailed information associated with meters that readily permit identification of the equipment in the original area.
- Number of underground services – We distribute the total number of services in the area SMUD proposes to condemn between overhead and underground based on consideration of the relative distance of UG (and OH) feeders. UG feeders represent 40 percent of the total feeder length. For the purposes of this report, we estimate that the number of underground service lines amount to 35 percent of all services in order to be conservative and reflect anticipated relatively greater reliance on secondary in serving underground customers. We believe that this distribution reasonably reflects the reality that as the footage of UG primary increases, so does the number of customers served through UG services.

In Table 9.4.2 we describe in additional detail how we inventory each system component, as well as how we determine unit cost (RCN).

In the following we provide further detail regarding our development of RCN for major components.

4.2.1 Rights of Way

PG&E's Electronic Document Management System (EDMC) identifies PG&E's interest in distribution land, land rights, etc. (rights of way) within the proposed condemnation area. PG&E has both rights of way and fee property covering transmission routes, substation sites, distribution lines, and other requirements within the area. It has 2,300 separate documented distribution land rights whose documentation fills 4 boxes. In consultation with PG&E's professionals, we value rights of way associated with the specific transmission lines SMUD proposes to condemn at $7.5 million. Within the original area, the value of 2,300 parcels related to distribution assets amounts to $16.1 million based on an average value per parcel of $7,000.

Within the proposed condemnation area, PG&E has the following types of land and rights of way:

- Communication easements
- Easements granted over fee lands
- Electric pole line easements
- Electric tower line easements
- Electric underground easements
- Fee property
- Railroad crossing and longitudinal rights
- Railroad rights of ways
- Other

Electric pole line easements include:

- Easements (rights of way)
- Easements for anchors guy stub and other equipment
- Rights of way across city properties
- Rear easement rights of way jointly held by PG&E and a telephone utility[28]
- Agreements, rights of way, or permits with the State of California
- Rights of way or permits with railroads.

[28] In older areas, utilities placed along rear property lines do not occupy public utility easements set aside by the developer.

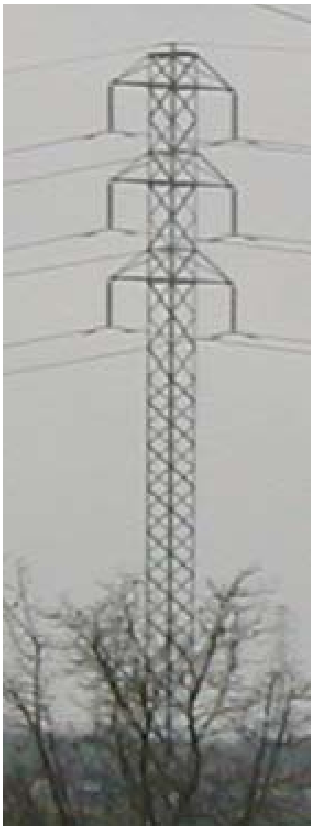
Underground easements in connection with underground distribution lines primarily relate to equipment located on private property in older areas.

Figure 4.2.2.1
60' Column Tower
Off of Industrial Blvd West Sac.

4.2.2 Transmission Lines

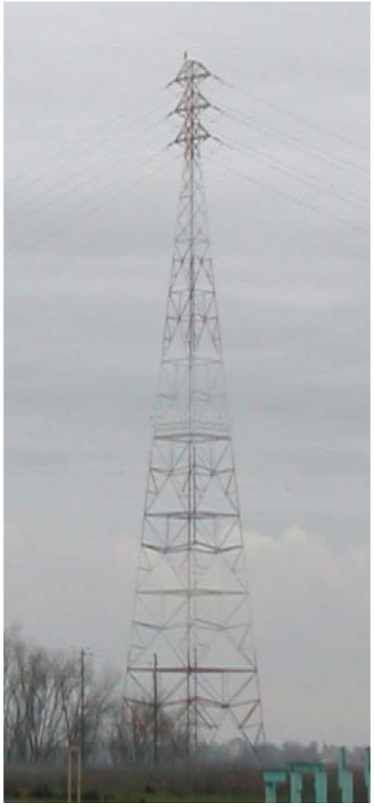
In Yolo County, PG&E relies on a variety of designs, from wood poles to steel tubular poles to steel lattice towers in its transmission system. Within the proposed annexation area PG&E has steel tubular poles which range in height from 65 feet to 110 feet (see Figure 4.2.2.1). PG&E's lattice tower designs range from column type towers 60 to 102 feet in height (see Figure 4.2.2.2) to lattice towers from 70 feet to 237 feet (see Figure 4.2.2.3) in height for major highway, river, and channel crossings. Those transmission structures over the rivers are outstanding tower crossings (see Figure 4.2.2.4).

Figure 4.2.2.2
60' Column Tower
Off I-80 and El Camino Ave. Sac.



PG&E's transmission assets are in very good condition. The galvanized steel braces have minimal indication of rust and all transmission insulators are intact. PG&E typically uses triangular construction Type T1 (Light duty pole top bracket), T-2- N (Heavy duty pole top bracket), and Type T1- DE structures for transmission lines using wood poles. Wishbone, vertical, and delta type construction are also used in some parts of the area. Transmission wood pole heights range from 55 feet to 85 feet in height depending on the design and geographic area requirements. Steel tubular pole designs are specified in PG&E's Civil Design Standard Drawing 051742. For double circuits, both

Figure 4.2.2.3
237' Lattice Tower
Deepwater Channel West Sac.



type I and II are used on the Deepwater Substation Tap Line. On the Davis to Brighton Line, eight single circuit tubular steel poles are used.

Figure 4.2.2.4
115 kV Deepwater Crossing
237' Towers on Either Sides of Channel

In Figure 4.1.2, we show a high level layout of PG&E's transmission lines impacted by condemnation. We have identified various line segments by letter designation. We have identified specific lines, which are lines SMUD proposes to condemn, (according to Staff), lines which PG&E will retain but will become stranded, and lines which PG&E will retain that are not stranded. In Appendix 4.2.2 we show further detailed diagrams concerning the lines SMUD proposes to condemn, those stranded, and other PG&E lines. In Table 9.4.2.2, we provide a summary description of each of these lines along with a more detailed determination of replacement cost new. In Table 4.2.2, we summarize total RCN value for transmission lines, which amounts to $34.0 million.

Table 4.2.2
Pacific Gas and Electric Company
RCN – Transmission Lines
As of December 31, 2004

	[A]	[B]	[C]	[D]	[E]
Line No.	Label	Description	Circuit Length	Unit RCN	RCN
			miles	$/mile	$ million
1	A	Brighton - Davis	25.90	597,288	15.47
2	B	West Sacramento - Davis	11.32	243,167	2.75
3	C	Woodland - Davis	11.62	261,942	3.04
4	D&E	Rio Oso - West Sacramento	12.08	567,256	6.85
5	F&G	Deepwater Tap #1 & #2	4.67	591,546	2.76
6	J	Woodland Biomass Tap	0.86	199,136	0.17
7	K	Woodland Poly Tap	0.30	231,157	0.07
8	L	US Post Office Tap	0.66	217,068	0.14
9	M	Wesson Hunt Tap	0.18	303,339	0.05
10	N	Plainfield Tap	3.00	154,051	0.46
11	P&Q	Rio Oso - Woodland #1 & #2	5.00	444,097	2.22
12	Total Transmission Lines		75.59	449,825	34.00

In addition to the above transmission lines, if SMUD takes PG&E's properties as proposed, 61.59 circuit miles of PG&E's 115 KV transmission system will no longer be of value to PG&E. These lines will be stranded as a result of SMUD's taking. RCN associated with these stranded lines amount to $39.16 million.

4.2.3 Distribution Substations

We develop an equipment inventory for each of the five distribution substations in the area based on single-line diagrams and in consultation with PG&E engineers and substation operations professionals. We develop RCN for each substation based on PG&E's current design standards, with current material costs and labor rates. PG&E operation and engineering personnel reviewed the inventory and RCN so determined at each site to verify the reasonableness. In Table 4.2.3, we summarize reproduction cost new of the five distribution substations. In Tables 9.4.2.3.1 through 9.4.2.3.5 we show for each substation, the major equipment, size of the site, a single-line diagram, and aerial photo.

The West Sacramento substation's higher relative cost reflects the additional cost of the transmission ring bus switching system and two transmission capacitor banks in the station which are not present in the other substations.

The Deepwater substation's higher cost recognizes that the station is designed to accommodate additional transformer banks. In early 2005, PG&E installed a new

45MVA transformer in the Deepwater Substation. The cost of this new equipment is not included in Table 4.2.3 since it was not in service as of December 31, 2004. The value of this new equipment is not reflected in Beck's or Staff's values. We include the cost of this improvement in our allowance for 2005-2007 capital additions (see Section 5).

Table 4.2.3
Replacement Cost New as of December 31, 2004
Distribution Substations in Original Area

	[A]	[B]	[C]	[D]
Line	**Substation**	**MVA**	**Unit Cost**	**RCN**
			$/MVA	$ million
1	West Sacramento	105	137,310	14.42
2	Deepwater	16	210,272	3.36
3	Davis	135	65,401	8.83
4	Woodland	120	74,865	8.98
5	Plainfield	10	104,738	1.05
6	Total	386	94,928	36.64

In Appendix 4.2.3, in addition to information concerning each substation, we show the detailed development of RCN.

4.2.4 Distribution

We previously described how we develop the inventory and replacement cost for other (not including the distribution rights of way and substations) distribution property in the area. We previously described how we developed the inventory and unit costs we rely on.

Table 4.2.4 shows a summary of RCN for PG&E's property in the original area. As shown, total RCN amounts to $439.25 million as of December 31, 2004. In Table 9.4.2.4, we show additional detail. The detailed development of RCN for distribution property (other than substations) as shown in Appendix 4.4.

Table 4.2.4
Replacement Cost New
Original Area
As of December 31, 2004

	[A]	[B]	[C]	[D]
		As of December 31, 2004		
Line No.	Description - Units	Units	Unit Cost	RCN
			$/	$ million
1	Transmission			
2	Rights of Way - miles			7.50
3	Lines - miles	75.59	449,825	34.00
4	Distribution			
5	Rights of Way - miles	2,300	7,000	16.10
6	Substations - MVA	386	94,928	36.64
7	OH Lines - miles	537.03	75,295	40.44
8	UG Lines - miles	353.53	522,996	184.89
9	Line Transformers - number	8,838	3,635	32.13
10	Secondary Lines - miles	374.65	17,450	6.54
11	Services - number	69,256	539	37.35
12	Meters - number	70,000	105	7.34
13	Miscellaneous			36.32
14	Total			439.25

4.3 Depreciation

In measuring depreciation, or more accurately condition, a number of approaches may be relied upon. One may rely on observed condition as the principal means to determine, by observation (inspection and testing in some instances), the condition of assets or to verify or confirm the condition determined by another approach. In lieu of or to supplement observed condition statistical approaches may be relied on. For the purposes of this report, we have relied principally on statistical approaches.

4.3.1 Service Life

Statistical approaches rely on mortality characteristics[29] to measure condition. These mortality characteristics reflect the distribution of property retirements of a group of properties over their average service life. In 1935, Robley Winfrey, then Research Associate Professor of Engineering Valuation at the University of Iowa, published Bulletin 125, titled "Statistical Analysis of Industrial Property Retirements." In this Bulletin, 18 curve types (shapes) are identified which generally explain the pattern of

[29] As used herein, mortality characteristics represent the number of retirements expected at a specified age.

industrial property retirements. When used in conjunction with average service life, these curves provide the expected number of retirements which will occur at any age for a group of similar property. These curve types are normally referred to as "Iowa Curves."

Since 1935, some additional curve types have been added to the original 18. In addition some other curve shapes have been developed. Altogether, these Iowa Curves remain widely used in the derivation of depreciation expense rates for accounting purposes and in the valuation of equipment to predict future retirements based on historical retirement experience.

For the purpose of this report, we use the curve types and average service lives used by PG&E in developing its depreciation expense rates for accounting purposes. These curve types and average service lives ascribe mortality (retirement pattern and life) characteristics to the facilities SMUD proposes to condemn comparable to those expected throughout PG&E's system, on average. For the purpose of this report, we have not independently verified the reasonableness of the individual curves for valuation purposes or for the purpose of valuing the facilities in the original area beyond observing that they are perhaps on the low side of the range we typically expect in connection with valuation matters. By using values on the low side, we tend to understate condition and hence understate value.

The need to use a tool such as the Iowa Curves comes about because value is a function of the utility (life) that a buyer can realize through the purchase of an asset (or group of assets). The Iowa Curves allow a reasonable estimate of the probable remaining life of the asset(s) based on a specified curve type, average service life, and age.

4.3.2 Present Worth Depreciation

The value of utility property relates to the capability of that property to generate cash and to support the financing required to fund acquisition (including construction) of that property over its remaining life. In order to recognize the value and distribute value equitably between the buyer and seller, depreciation must recognize this value contribution and financing requirement. To do so we must recognize in depreciation a present worth factor. Properly developed, present worth depreciation results in a value for property equal to the indebtedness associated with that property. Very simply, properly applied, use of present worth depreciation produces a result whereby the value of an asset at any point during its life is equal to the outstanding debt associated with securing the asset.[30]

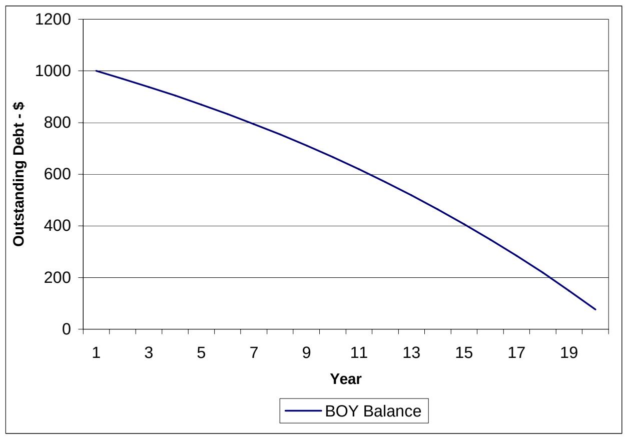
[30] In supporting the use of present worth depreciation in connection with the Turlock Irrigation District's acquisition of certain PG&E property, a Stone & Webster witness addressed it in a slightly different

An example will aid in understanding this concept.

Both Beck and Staff suggest that SMUD will finance an acquisition of PG&E's original area assets by issuing taxable revenue bonds. In Figure 4.3.1 we show, for 20-year revenue bonds, the outstanding principal by year assuming a 6.25 percent interest rate.

Figure 4.3.1
Outstanding Principal
20 yr. 6.25 % Bonds

	Debt			
	BOY	Payment		
Year	Balance	Interest	Principal	Total
1	1,000.00	62.50	26.46	88.96
2	973.54	60.85	28.12	88.96
3	945.42	59.09	29.87	88.96
4	915.55	57.22	31.74	88.96
5	883.81	55.24	33.72	88.96
6	850.08	53.13	35.83	88.96
7	814.25	50.89	38.07	88.96
8	776.18	48.51	40.45	88.96
9	735.73	45.98	42.98	88.96
10	692.75	43.30	45.67	88.96
11	647.08	40.44	48.52	88.96
12	598.56	37.41	51.55	88.96
13	547.01	34.19	54.77	88.96
14	492.24	30.76	58.20	88.96
15	434.04	27.13	61.83	88.96
16	372.21	23.26	65.70	88.96
17	306.51	19.16	69.81	88.96
18	236.70	14.79	74.17	88.96
19	162.53	10.16	78.80	88.96
20	83.73	5.23	83.73	88.96
		779.25	1,000.00	1,779.25



With straight-line depreciation[31], for the value an asset with a 20-year life and an initial value of $1,000 will decline in a straight line at the rate of $50 per year. Figure 4.3.2 superimposes the value of the asset assuming straight-line depreciation on Figure 4.3.1.

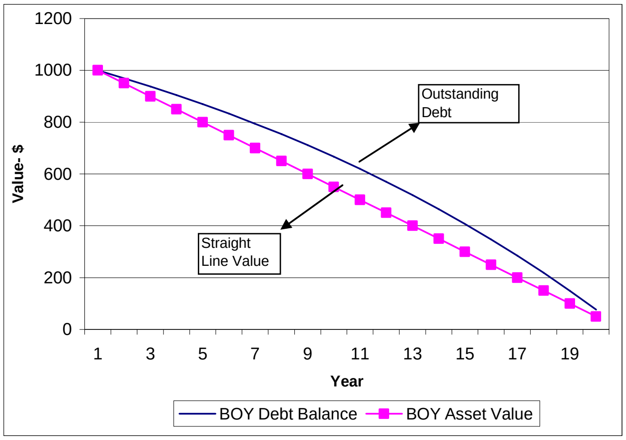
As shown in Figure 4.3.2, straight-line depreciation results in a value for the asset that is less than the outstanding debt used to finance the asset, except when placed in service and at the end of its life.

fashion. Stone & Webster cites the definition of depreciation set forth in the Iowa Engineering Experiment Station Bulletin 156 titled Condition Percent Tables for Depreciation of Unit and Group Properties as: "Depreciation of a unit of physical property at any age is the difference between the present worth of its present probable operation returns or services and the present worth of its probable future operation returns or services if it was new".

[31] Straight line depreciation is the same as present worth depreciation with a zero percent interest rate.

Figure 4.3.2
Outstanding Principal
Vs Straight Line Depreciation

Year	BOY Value	Depreciation
1	1,000.00	50.00
2	950.00	50.00
3	900.00	50.00
4	850.00	50.00
5	800.00	50.00
6	750.00	50.00
7	700.00	50.00
8	650.00	50.00
9	600.00	50.00
10	550.00	50.00
11	500.00	50.00
12	450.00	50.00
13	400.00	50.00
14	350.00	50.00
15	300.00	50.00
16	250.00	50.00
17	200.00	50.00
18	150.00	50.00
19	100.00	50.00
20	50.00	50.00
		1,000.00



Present worth depreciation with a 6.25 percent rate, on the other hand, results in an asset value equal to the outstanding indebtedness used to support the acquisition of the asset, at any time in its life. Why would a seller willingly sell property for less than the outstanding indebtedness used to finance that asset? Since the seller must use the sale proceeds to pay off the debt, the seller loses money on such a sale. Further, most bond indentures, resolutions, and ordinances would prohibit such a sale without assurances that the value of the remaining assets is sufficient to secure the debt.

In the foregoing, we have addressed the question of our use of present worth depreciation. In this discussion, we have tied present worth depreciation to financing requirements. Present worth depreciation also results when one considers the present worth of the annual benefits of the asset in question.

Again a simple example will help explain this concept. Assume a pole has a service life of 40 years. The present day value of the rights for the use of the pole during the first 20 years exceeds the present day value for the rights to use the pole during the last 20 years (years 21 through 40). Following a replacement cost approach, the purchase today of a pole with a remaining life of 20 years has the equivalent value as the rights to the use of a new pole for the first 20 years of its life.

For the purpose of this report, we reduce replacement cost new to reflect depreciation using the probable lives estimated by the curve types and average service lives that underlie PG&E's existing depreciation expense rates, and present worth depreciation using a 6.25 percent interest rate.

In Table 9.4.3 we show the curve types and average service lives used for the purpose of this report.

4.4 Replacement Cost New Less Depreciation

In Table 4.4, we summarize our RCN and RCNLD values as of December 31, 2004. These amounts include no allowance for going concern and other considerations. As shown, we find RCN to total $439.25 million and RCNLD, $345.38 million. In Appendix 4.4 we show in detail our RCNLD calculations.

Table 4.4
Summary RCN and RCNLD
Original Area Facilities SMUD Proposes to Condemn
As of December 31, 2004

	[A]	[B]	[C]	[D]
		As of December 31, 2004		
Line No.	Description	RCN	Condition Percent	RCNLD
		$ million		$ million
1	Transmission			
2	Rights of Way	7.50	100.00%	7.50
3	Lines	34.00	64.96%	22.09
4	Distribution			
5	Rights of Way	16.10	100.00%	16.10
6	Substations	36.64	72.04%	26.40
7	OH Lines	40.44	69.94%	28.28
8	UG Lines	184.89	83.03%	153.52
9	Line Transformers	32.13	69.71%	22.40
10	Secondary Lines	6.54	73.79%	4.82
11	Services	37.35	85.25%	31.84
12	Meters	7.34	71.70%	5.26
13	Miscellaneous	36.32	74.78%	27.16
14	Total	439.25	78.63%	345.38

5.0 RCNLD AS OF JANUARY 1, 2008

In the foregoing, we developed values based on cost levels which existed in late 2004. However, any forced sale of the subject property through condemnation realistically will not occur prior to January 1, 2008.[32] In order to acquire PG&E's facilities, we understand that:

1. LAFCo must approve the annexation,
2. voters in the original area must approve,
3. SMUD must hold hearings and approve a Resolution of Necessity,
4. SMUD must obtain and approve an appraisal of fair market value and offer PG&E not less than the appraised value,
5. SMUD must sue to condemn,
6. SMUD's right to take the facilities must be affirmed by a judge after a trial
7. A jury must determine, after a trial, the fair market value
8. Appellate courts must affirm if decisions are appealed
9. SMUD must obtain financing, and the sale closed[33].

The relevant value therefore becomes the fair market value as of the date of closing[34]. For the purpose of this repot, we assume a closing at the beginning of 2008. Realistically we believe this date represents the earliest date SMUD can close on these properties.

5.1 Capital Additions

In addition to the facilities in the original area which are in service as of December 31, 2004, PG&E plans to make significant capital improvements over the next several years. These improvements are intended to accommodate growth and to enhance reliability. They fulfill PG&E's continuing obligation to serve the area until relieved of that obligation. One of these improvements – a 45 MVA transformer at Deepwater Substation

[32] We note that in SMUD's July 29, 2005 "Application for Annexation of the Cities of West Sacramento, Davis, and Woodland and Unincorporated Areas of Yolo County and Related Sphere of Influence Amendment" submitted by SMUD to LAFCo, SMUD assumes the takeover date to be October 2008. We believe that based on SMUD's suggested schedule, October 1, 2008 represents the absolute earliest.

[33] In addition based on our understanding of Staff's proposal, SMUD would need to permit and construct a new 18 mile transmission line and other facilities to separate from PG&E.

[34] The earliest possible date of valuation is the "date of commencement of the proceeding" (California Code of Civil Procedure section 1263.120). However, typically the total amount due the seller represents the fair market value as of the valuation date plus improvements made to the date of closing.

worth approximately $1.9 million – was installed this year. The California Central Valley is one of the fastest growing areas in the country, and the Woodland-Davis-West Sacramento area is no exception. Failure to recognize the value PG&E plans to add will significantly understate the value of the facilities if PG&E is forced to sell circa 2008.

We categorize PG&E's planned capital additions into the following:

- Capital additions required to extend service into new areas and to attach new customers. These capital additions are required to accommodate growth in the area, in fulfillment of PG&E's obligation to serve.
- Capital additions to enhance service reliability. These capital projects may involve reconductoring lines and transformer upgrades.
- Capital additions to PG&E's distribution system including emergency repairs due to storm or other events.
- Capital additions to transmission lines including capacity upgrades.
- Distribution preventative maintenance (FACTS tags).
- Distribution capacity, distribution reliability, cable replacement, pole replacement, overhead to underground conversions, and non pole related capital work.
- Transmission upgrades

Table 5.1.1 summarizes planned improvements for 2005, 2006 and 2007.

Table 5.1.1
Summary of Capital Additions
Original Area

	[A]	[B]	[C]	[D]
Line	Description	2005	2006	2007
		$ million	$ million	$ million
1	Growth	4.00	4.08	4.16
2	Service Reliability	1.13	2.00	2.51
3	Emergency Distribution	1.50	1.50	1.50
4	Transmission	9.08	7.62	0.69
5	Budgeted Additions	1.90	1.90	
6	Total	17.61	17.10	8.87

We include in 2005 capital additions of $1.9 million to increase capacity in the Deepwater substation as we describe in section 4.2.3. We include in 2006 capital additions of $1.9 million to upgrade the UC Davis to Davis transmission line to 115 KV.

We base the growth component on actual 2004 capital investment, escalated at a conservative 2 percent per year. The other categories represent actual budgeted projects as identified in Appendix 5.1.1.

5.2 Change in Value – 2004-2008

Table 4.4 summarizes RCN and RCNLD for facilities in service as of December 31, 2004, without regard to later additions. However, assuming a transaction date of January 1, 2008, a value as of December 31, 2004 is of little relevance. Besides adding capital additions, we must adjust the value of preexisting facilities to reflect 1) price level increases during the period, 2) retirements during the period, and 3) reduced condition due to increased age. Table 5.2 summarizes RCN and RCNLD as of December 31, 2004 and as of January 1, 2008

Table 5.2
Summary of RCN and RCNLD
As of December 31, 2004 and January 1, 2008

	[A]	[B]	[C]	[D]	[E]
Line		As of December 31, 2004		As of January 1, 2008	
No.	Description	RCN	RCNLD	RCN	RCNLD
		$ million	$ million	$ million	$ million
1	Plant in Service as Of December 31, 2004				
2	Transmission				
3	Rights of Way	7.50	7.50	7.96	7.96
4	Lines	34.00	22.09	33.59	20.89
5	Distribution				
6	Rights of Way	16.10	16.10	17.09	17.09
7	Substations	36.64	26.40	36.34	25.64
8	OH Lines	40.44	28.28	39.71	26.98
9	UG Lines	184.89	153.52	192.45	151.77
10	Line Transformers	32.13	22.40	31.35	20.94
11	Secondary Lines	6.54	4.82	6.77	4.52
12	Services	37.35	31.84	38.96	31.96
13	Meters	7.34	5.26	7.46	4.92
14	Miscellaneous	36.32	27.16	36.83	25.91
15	Total	439.25	345.38	448.51	338.57
16	Growth 2005, 2006, and 2007			45.07	44.09
17	Total as of January 1, 2008			493.58	382.66

We show that the detailed development of RCN and RCNLD as of January 1, 2008 in Table 9.5.2.

6.0 Going Concern Value

In addition to the value of the physical facilities (as measured using cost-based measures such as RCNLD), utility property typically has additional value associated with operating as a going concern. The value of the facilities relates to the ability to deliver electricity to customers. If there are no customers attached, the value is limited to the potential to deliver energy. RCNLD measures only value of the physical assets. Obviously, operating facilities that have customers attached (and taking and paying for electric service), have a higher value than facilities that do not have customers attached. The value of operating facilities includes the value of the physical assets (RCNLD) plus an increment of value associated with operating as an ongoing business enterprise.

An entity condemning utility property usually intends to operate the property in essentially the same manner and for the same purpose (the provision of utility service) as the incumbent. In simple fact, when utility property is acquired through eminent domain, the condemning entity does not desire the property but the business. This is certainly the case with SMUD's proposed takeover.

For over one hundred years, courts have recognized various intangible factors in valuing utility property in connection with condemnation. Factors that courts have recognized include efficiency of the system, length of time necessary to construct a new system, and income and profits gained or lost for the utility to establish its business[35].

The concept of going concern value can cover a number of factors. Some of these factors include:

- The cost of attaching customers to the system
- The cost associated with maintaining plant before individual customers are connected
- The value of maps, records, and other information relating to the facilities and to the businesses supported by the facilities
- The value associated with the use of the facilities to generate income through use in business activities unrelated to the core business

The first three above relate to the costs incidental to attaching customers to the system.

Attaching customers involves various costs. In order to attach customers to the system, the utility incurs certain capital costs. The utility also expenses certain costs. RCNLD

[35] See Nichols on Eminent Domain (14A-12), Kennebec Water Dist. v. City of Waterville, 97 Me, 57 A.6 (1902).

includes consideration of the value associated with costs that are included in RCN. RCNLD does not include an allowance for any costs expensed or costs not reflected in the RCN value.

Costs related to extending service to customers that the utility expenses represent an element of going concern value. The utility normally expenses costs such as sales and marketing related costs in advance of attaching the customer. The costs of physically connecting customers to the system (services, meters, etc.) are capitalized (and hence normally included in the RCNLD value). These capital costs do not include the initial setup of individual customer records which we generally estimate in the range of $5 to $10 per customer. Thus, the utility incurs a cost of $5 to $10 per customer in sales, marketing, and setting up customer records that are not included in RCN but that the utility incurs to establish the business desired through condemnation. In this case, PG&E has incurred cost to develop its business, now desired by SMUD.

The cost related to facilities in service prior to attaching individual customers is a function of the level of the plant cost and the rate at which the utility adds customers to the system. RCN represents the current cost of constructing plant. It includes cost associated with the materials, labor, and equipment used. It includes cost from the initial permitting, planning, and design, through completion. RCN does not include consideration of any cost incurred once construction is completed. However, typically once construction is completed it is some time before the facilities are fully utilized by customers. It takes time from completion of construction to attach all of the customers to the system is designed to accommodate. Until such time as the utility attaches all customers in a particular area fixed costs (financing and operating) are incurred and carried by the owner until such time as customers are added. These costs represent an element of going concern as they are incurred in connection with the “assembly” of the business. Since the utility does not incur facility costs associated with services, meters, etc. until shortly before it extends service to the customer, financing and operating costs associated with lines (overhead and underground), line transformers, and streetlights represent significant elements of going concern value. We estimate an allowance for this element of going concern value in the range of 10 to 15 percent of total RCN. An electric utility creates and maintains extensive records (including maps) relating to the facilities and customers served. These include but are not limited to:

- Customer accounting records including:
  - Payment
  - Usage history

- Equipment records including:
  - Inventory
  - Maintenance
  - Inspections
  - Settings
- Maps including:
  - Circuit maps
  - Plat maps
  - Location of switches
  - Interconnections
  - Normal power flow

These records are valuable to the operator of the facilities and cost the utility substantial amounts to develop and maintain[36]. A further element of going concern value is the value of these records. Setting up customer records was mentioned above; there is further value in the utility's constant upgrading and expanding of the information reported on the records. The same is true of the utility's constant upgrading and expanding of equipment records. We estimate a reasonable allowance for this element in the range of 5 to 10 percent of total RCN.

In the foregoing, we have identified going concern value considerations totaling $5-$10 per customer plus 15 to 25 percent of RCN. These allowances reflect going concern value in terms of facilities operating to provide electric utility service. Thus, this (plus the RCNLD value of the facilities) represents the value of continuing to use facilities as the utility has used them in the past to provide electric utility service. In many past valuations the allowance for going concern value stopped at this point. However, the facilities, especially if we consider the established customer base attached to them, may also have value associated with their use supporting other business activities unrelated to providing electric utility service. Just as new technology and new uses for existing technology can increase (or decrease) values in any business, emerging new technologies have in the last few years enhanced the value of existing operating electric distribution systems. These emerging technologies will be discussed next. Any determination of fair market value must recognize the added value to PG&E's Yolo system not yet captured in the analysis.

[36] The GIS and other databases described in Section 4.1 are examples.

PG&E rents space on its facilities to others.[37] For example, Figure 6.0 is a photo of PG&E's 224 foot transmission tower located at Garden Hwy and I-80. On this tower we see a number of PCS antennas (digital cellular service). Based on this photo and the usual configuration of antennas, there are 15 separate antennas owned by 5 separate PCS carriers. Though not seen in the photo, there are also a number of structures on this site for supporting equipment. PG&E currently receives about $100,000 per year in PCS revenue from this tower alone.[38] Space on at least 11 PG&E transmission towers and substations in the original area is rented for PCS antennas, fiber optics cables, and other equipment. Although the equipment is easily visible and providing PG&E revenue, Beck and Staff never mention it or accord it any value.

Figure 6.0
224' Tower with Attachments
Garden Hwy and I-80

In addition, PG&E also uses some of its poles and towers to support its fiber optic communication system. There is value associated with this equipment and the use of PG&E's poles and towers to support it. For the purposes of this report, we did not separately value this equipment or PG&E's related equipment and the implications on PG&E of its loss. An increment of our going concern value provides for this additional value.

A number of electric utilities, including PG&E, are currently exploring the business case for using the existing electric distribution system to provide "broadband over power line" (BPL) service to individual customers, either directly or through the lease or resale of broadband capacity. Providing this service will generate an additional source of revenues for the owner of the electric distribution system. Further, BPL may offer valuable benefits to electric utilities and their customers in addition to generating revenue from selling high-speed internet service. The technology may enable the utility to more effectively monitor its

[37] In this regard, we limit our discussion to agreements which do not embody a reciprocal arrangement where parties share joint use of each other's facilities.

[38] To put this revenue stream into perspective, the replacement cost new of this 224 foot tower is about $400,000. This $400,000 amount represents the value (before depreciation) of the tower in connection with providing electric service (the business SMUD desires to condemn). Assuming a 6.25 percent capitalization rate, a $100,000 annual revenue stream has a fair market value of $1.6 million. In the event SMUD takes the properties it is considering, PG&E will lose about $1.6 million in value unrelated to the electric business SMUD desires. PG&E needs compensation for this loss either through severance damages or in the purchase price. For the purposes of this report, we consider this value in our going concern allowance.

circuits, measure usage, locate outages, and bill customers. San Diego Gas & Electric has recently announced a pilot project to explore these potential benefits.

BPL represents a new technology to provide a service (high-speed internet or "broadband"), comparable to that provided by local telephone service providers (DSL), cable television providers, and others. BPL has a number of advantages over competing technologies. BPL has faster data transfer speeds. Internet access is available through any electric outlet, eliminating the need for internal wiring or wireless networking with its related security problems. The broadband market is and is anticipated to remain, highly competitive for some time. As evidenced by the following, not only is there a great deal of interest in the technology, but major players are investing substantial sums in it:

- Associate Press (AP) in a release dated November 27, 2004 announced the use of BPL by Broadband Horizons to extend service to about 6,000 rural customers in central Texas. AP also noted ongoing pilot projects in Manassas, VA and by Cinergy Corp.
- The Energy Daily, in its January 13, 2005 issue, cited a Pennsylvania State University study that concluded under ideal conditions, BPL can transmit data in amounts far exceeding DSL or cable capacity. Energy Daily also indicated that Manassas was currently providing BPL, Cinergy announced a partnership with Current Communications Group LLC to begin mass deployment in March, and more than a dozen companies were testing the technology.
- In its May-June 2005 issue, Hometown Connections stated it had formed a strategic partnership to enable members of the America Public Power Association (APPA) to deliver BPL services. SMUD is a member of APPA and Jan Schori, SMUD's General Manager, is the immediate past chairperson.
- The Energy Daily, in its July 8, 2005 issue, cited a $100 million investment in Current Communications Group LLC by Google, Inc., Goldman Sachs & Co., and the Hearst Corporation.
- The New York Times announced in its August 5, 2005 issue, that IBM had announced a partnership with Center Point Energy to develop BPL services.

On September 8, 2005, CPUC Commissioner Susan P. Kennedy described a proposed set of CPUC rules as "a critical step toward clearing a regulatory path for developing BPL in California." These rules are intended to expedite BPL prospects and to affirm the unregulated nature of BPL. Further, this year the FCC adopted regulations intended to expedite the development of BPL. Further we understand that cable operators are not considered communication providers and hence cannot be forced to resell broadband capacity. The latter may well further stimulate the desire for BPL capacity. These actions all go toward encouraging electric utilities to explore opportunities related to BPL. These opportunities represent anq increment of value.

The ultimate value which BPL will bring to a utility offering the service is a function of the price charged, the number of customers served (saturation), the incremental capital and operating costs, the estimated cost to attach customers, the expected life of the commercial venture, and the return expectations. These elements are not independent, but tend to affect one another. For example, as price increases, we expect saturation to decrease. As more is spent to attract new customers such as advertising, promotions, discounts, etc. increases, we expect that the number of customers served will increase.

The courts have long recognized the incremental value attributable to acquiring a going concern. In fact, the price paid by Turlock Irrigation District for certain PG&E facilities included an allowance of 10 percent of RCNLD for going concern value and Turlock also agreed to a service area agreement as part of the transaction. We believe that an allowance of 10 percent of RCNLD is wholly inadequate to compensate PG&E for the cost incurred in developing its business in Yolo County, plus the present value in PCS and fiber, the potential value in connection with BPL, and other uses. We therefore use a conservative going concern value allowance of 25 percent of RCN for the purpose of this report.

7.0 Total Value

In the foregoing, we have developed RCNLD as of December 31, 2004 and January 1, 2008 and an allowance for going concern value. There are two additional elements we need to consider to develop total fair market value. These elements are other assets and liabilities incidental to the property condemned. We will also include allowances for stranded investment.

7.1 Other Assets

In addition to the fair market value of its condemned assets, to remain whole PG&E needs to be compensated for certain other tangible assets not included in RCNLD or going concern value. These other tangible assets include:

- Accounts receivable
- Unbilled revenues
- Construction work in progress

7.1.1 Accounts Receivable

Accounts receivable represent the dollar amount which PG&E has billed its customers but not yet received payment. Upon takeover of PG&E's facilities by SMUD, PG&E cannot effectively enforce collection of these funds. Therefore, SMUD should compensate PG&E for receivables associated with customers in the area condemned. In return, PG&E should assign its receivables associated with these customers to SMUD. We estimate receivables as of January 1, 2008 of $10.0 million.

The amount due to PG&E for accounts receivable should ultimately be determined as the amount reported in PG&E's billing records as of the date SMUD takes over its property. Once PG&E assigns receivables to SMUD, SMUD has a vested interest and will be responsible for collection of amounts due from customers in the area, and has the ongoing customer relationship to insure recovery.

7.1.2 Unbilled Revenues

Unbilled revenues represent electric service provided to customers since the preceding meter reading date that customers have not yet been billed for. Upon takeover of PG&E's facilities by SMUD, PG&E will have no way to effectively enforce collection of such revenue; therefore, SMUD should compensate PG&E for an asset, which SMUD in fact acquires. Unbilled revenues due PG&E can be computed as follows:

1. All customer meters will be read by PG&E immediately preceding closing.
2. Consumption for each customer will be determined as of the meter reading in Item 1 above less the meter reading last billed by PG&E.
3. Revenues for each customer will be determined in the same manner that PG&E uses in the normal course of business to bill customers for partial period service.

For the purposes of this report, we estimate unbilled revenues as of January 1, 2008 equal to 70 percent of receivables or $7.0 million.

7.1.3 Construction Work in Progress

Construction work in progress (CWIP) represents costs which have been incurred in connection with the construction of capital projects not yet completed. CWIP may also consist of projects recently completed but not recorded in PG&E's GIS databases. As we describe above we develop RCNLD based on an inventory of PG&E property reported in various PG&E databases. To the extent property is not included in these databases, the value associated with that property is not reflected in our RCNLD value. There is a certain lag time between the time that property goes into service and is closed to plant accounting and when it is recorded in PG&E's databases. This delay may also be considered CWIP.

CWIP represents PG&E's actual costs of improving the system, which are not yet reflected in RCNLD. These costs are similar to accounts receivable in that they tend to vary seasonally and can change from day to day and month to month. The level of CWIP is dependent upon the nature of projects under construction and the extent of construction at the time ownership is transferred. The amount due to PG&E should ultimately be determined based on the amount of CWIP as of the date the facilities are taken over by SMUD. For the purposes of this report, we estimate construction work in progress associated with service in the original area as of January 1, 2008 to amount to 25 percent of estimated 2007 additions. This amounts to $3.5 million (Table 5.1.1, $14.1 million times 25 percent).

7.1.4 Total Other Assets

Based on the foregoing, the total value of other assets for the purposes of this report amounts to $20.5 million (receivables of $10.0 million plus CWIP of $3.5 million plus unbilled of $7.0 million).

7.2 Liabilities

If assets are transferred to SMUD through condemnation, SMUD will assume title to not only PG&E's electric utility assets in the original area, but the associated liabilities as well. We are unaware of any liability associated with PG&E's electric utility property in the original area.

Though we are unaware of any specific legal liability associated with the property SMUD proposes to condemn, in the normal course of business PG&E incurs certain costs associated with removing property from service. To some degree, the material removed from service can be sold as salvage. We normally refer to these two elements collectively as net salvage. Net salvage represents the extent that salvage proceeds exceed cost of removal. If removal costs exceed proceeds (which is the normal case) net salvage is negative. We understand SMUD likewise incurs costs in removing property from service though SMUD may not account for it in the same manner.

In developing depreciation rates, we typically include an allowance to reflect net salvage. In this regard, depreciation rates are designed to recover the total investment cost associated with an asset (or group of assets) over its service life. We determine total investment cost as the sum of the original cost plus cost of removal less salvage proceeds.[39]

Typically, we determine the allowance for net salvage we include in depreciation rates by dividing the net salvage actually incurred during a period by the original cost of plant retired during that period. We use this ratio as a guide to determine the net salvage amount to include in depreciation rates. We understand that PG&E develops its depreciation rates in a similar manner.

In order to adjust value to reflect the "liability" associated with net salvage, we must consider two factors. First, the net salvage allowances included in PG&E's depreciation rates are based on the ratio of historical net salvage divided by the **original cost** of retirements. Thus, this ratio applied to the original cost of the plant SMUD proposes to condemn represents allowance for net salvage. If we applied this ratio to RCN, we would overstate the potential net salvage liability due to price level changes between the date of original construction and today (Beck and Staff make this error). Since we do not attempt to develop original cost in the area SMUD proposes to condemn, we can adjust our RCN values to a reasonable original cost measure by "back-trending" using the Handy-Whitman Index of Public Utility Cost.

[39] Original cost less net salvage.

Table 7.2
Pacific Gas and Electric Company
Summary – Reduction in Value Due to Net Salvage
As of January 1, 2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Description	RCN	Average Age	Net Salvage	Remaining Life	Present Worth Factor	Affect on Value
		$ million	years	$ million	years		$ million
1	Transmission						
2	Rights of Way	7.96	40.1	-			
3	Lines	33.59	40.1	(2.53)	21.4	0.305	(0.77)
4	Distribution						
5	Rights of Way	17.09	19.4	-			
6	Substations	36.34	30.9	-	28.2		
7	OH Lines	39.71	28.6	(7.00)	11.8	0.238	(1.67)
8	UG Lines	192.45	16.2	(6.35)	30.9	0.713	(4.53)
9	Line Transformers	31.35	21.2	0.44	16.5	0.349	0.15
10	Secondary Lines	6.77	17.0	(0.99)	16.9	0.343	(0.34)
11	Services	38.96	17.4	(12.23)	28.3	0.180	(2.20)
12	Meters	7.46	18.3	-	16.9		-
13	Miscellaneous	36.83	15.7	(6.30)	18.8	0.279	(1.76)
14	Total	448.51	21.3	(34.95)			(11.11)

We then apply the net salvage value percent to this back-trended cost to determine the total liability associated with the property in the original area. However, these costs will not be incurred on the valuation date but in the future as equipment is retired. Net salvage will not be incurred until the owner retires the property. Thus, the total liability incurred at retirement must be discounted back to the valuation date.

In Table 7.2, we summarize the value of net salvage as of January 1, 2008. Table 9.7.2 shows a more comprehensive development of net salvage and Appendix 7.2 shows the detailed calculations underlying these tables. In Table 7.2 (Table 9.7.2 and Appendix 7.2), we show total RCN, the composite trend factor used to restate RCN to an original cost measure, the net salvage amount estimated at the time of retirement, and the present worth of that net salvage today based on use of a 6.25 percent present worth factor.

As shown in Table 7.2, total net salvage associated with the property SMUD proposes to condemn amounts to negative (cost of removal exceeds salvage value) $34.95 million as of the date of retirement. The reduction in fair market value as of January 1, 2008 due to net salvage amounts to $11.11 million.

7.3 Total Value

Table 7.3 summarizes our determination of fair market value as of January 1, 2008. As we show in this table, we determine the value of the facilities as of December 31, 2004 to be $345.38 million ($439.25 million un-depreciated), before consideration of going concern value and other elements of value.

Table 7.3
Pacific Gas and Electric Company
Property SMUD Proposes to Condemn
As of January 1, 2008

	[A]	[B]	[C]
Line No.	Description	RCN	RCNLD
		$ million	$ million
1	In Service as of December 31, 2004		
2	Transmission		
3	Rights of Way	7.50	7.50
4	Lines	34.00	22.09
5	Distribution		
6	Rights of Way	16.10	16.10
7	Substations	36.64	26.40
8	OH Lines	40.44	28.28
9	UG Lines	184.89	153.52
10	Line Transformers	32.13	22.40
11	Secondary Lines	6.54	4.82
12	Services	37.35	31.84
13	Meters	7.34	5.26
14	Miscellaneous	36.32	27.16
15	Total as of December 31, 2004	439.25	345.38
16	Change in Value 12/31/04 to 1/1/08	9.25	(6.82)
17	Facilities in Service as of 12/31/04	448.51	338.57
18	Plant Additions	45.07	44.09
19	Total as of January 1, 2008	493.58	382.66
20	Other Elements of Value		
21	Going Concern Value @ 25%		123.39
22	Other Assets		20.50
23	Liabilities		(11.11)
24	Fair Market Value as of January 1, 2008		515.44
25	Stranded Investment		36.32
26	Severance		14.12
27	Total		565.88

To reflect the change in value of these facilities between December 31, 2004 and January 1, 2008 we deduct $6.82 million. This adjustment reflects consideration of the loss in value due to retirements and further depreciation, offset by expected price level increases. As shown in Line 17 of Table 7.3, we find the value of the electric system properties (before consideration of going concern and other elements of value) which existed at the end of 2004 to be $338.57 million ($448.51 million un-depreciated) as of January 1, 2008.

To this $338.57 million value we add $44.09 million to reflect the value (net of depreciation) associated with forecasted capital additions during the three year period. Thus, we find a total value, prior to allowance for going concern and consideration of other assets and liabilities, of $382.66 million, as shown in Line 19. After consideration of going concern value, other assets, and liabilities we find the total fair market value of PG&E's property in the proposed condemnation area to amount to $515.44 million as of January 1, 2008.

In the above, we independently developed the fair market value of $515.44 million for PG&E's facilities (business) in the original proposed condemnation area. With 70,000 customers in the area, the average value per customer amounts to about $7,400. We can test the reasonableness of this average by examining the ratio of this value to PG&E's system wide net original cost. We show this comparison in Table 9.7.3.1. As shown, PG&E's system wide average net original cost per customer, restated to 35 percent underground, amounts to $2,866 per customer. With our fair market value of $7,363 per customer the ratio of fair market value to average system wide net original cost amounts to 2.57 times.

This ratio appears more than reasonable in light of our understanding that the California State Board of Equalization uses a ratio of 3.1 and Beck used a 2.3 times ratio in valuing PG&E's facilities in connection with a potential condemnation by East Bay MUD.

7.4 Stranded Investment / Severance

In the foregoing, we develop the total fair market value of the facilities in the original area proposed to be condemned. These facilities represent the PG&E property SMUD desires to acquire through its proposed condemnation.

In addition to the property SMUD proposes to acquire, if that property is indeed taken, the value of certain other PG&E facilities will be adversely affected. In this report, we address facilities affected in two ways. First are facilities which become stranded and no longer useful to PG&E. Second are facilities which because of changes in power flows no longer have sufficient capacity to meet requirements.

In Section 4, we describe the PG&E transmission lines which will become stranded. As a result of a taking of the property as proposed by SMUD we find that PG&E will no longer require 61.59 miles of transmission lines in the area to serve its remaining customers. As a result of the taking, these lines will no longer be of value to PG&E, and as a result PG&E should be compensated for the value lost. In Section 4.2.2 we show the development of the $39.16 million RCN value as of January 1, 2008 associated with these lines. The RCNLD value associated with these lines amounts to $27.84 million.

In addition to these stranded lines, as a result of a taking by SMUD, the value of PG&E's Brighton substation will by dramatically reduced. The Brighton 230/115 KV substation is used to transform voltage from 230 KV to 115 KV. This transformation is accomplished through 113 MVA and 420 MVA transformers. The 2008 summer peak loading before a taking by SMUD amounts to 197 MVA. In the event SMUD takes the proposed area, the summer peak load amounts to only 31.3 MVA. PG&E installed the 420 MVA transformer bank in 2004 at a cost of $8 million. PG&E will have no need for this transformer in the event SMUD takes PG&E's facilities. Escalating the $8.0 million 2004 cost to January 1, 2008, we find RCN of $8.66 million. Based on an estimated service life of 43 years and the 4-year age of the transformer in 2008, RCNLD as of January 1, 2008 amounts to 8.48 million.

Thus PG&E's total stranded investment as a result of SMUD taking PG&E's facilities in the original area proposed to be condemned amounts to $36.32 million ($27.84 million related to transmission lines plus $8.48 million for the Brighton substation).

Both Beck and Staff evaluated the impact of the annexation on the SMUD transmission system only. They did not address the impact on the regional transmission system. PG&E Electric Transmission and Distribution Engineers evaluated the impact of the SMUD annexation on the bulk transmission system in Northern California in accordance with the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) Planning Standards. The PG&E study did not address other important issues; such as, control area, future service flexibility, and operation and maintenance. The study did identify potential reinforcements needed to overcome each criteria violated caused by the SMUD Annexation Project. An initial estimate of the costs for the required reinforcements was provided. Figure 9.7.4.1 shows the summer peak power flow pattern for the current load forecast for those substations in the SMUD condemnation area under 1-in-10 year adverse weather conditions before the proposed condemnation.

SMUD assumed that PG&E would serve UC Davis from other PG&E facilities. However, since PG&E's existing 60 kV system in the area does not have spare capacity to serve UC Davis, PG&E assumed, for the purpose of this preliminary study, in order to be conservative, that UC Davis would still be served from Davis Substation. Such an arrangement would require that SMUD wheel power through its system to serve the UC Davis load. While potential severance damage may result from this arrangement, to be conservative we have not attempted to separately measure them. With the 36.6 MW of load at UC Davis, the originally proposed condemnation area would result in a total customer load of about 391 MW in 2008 and 411 MW in 2014.

The annexation area customer load is currently served from PG&E's Rio Oso 115 kV Substation and Brighton 115 kV Substation from the north. The power flow direction is shown in Figure 9.7.4.1. Following a SMUD condemnation, this customer load would be served from SMUD's transmission system from the south as shown in Figure 9.7.4.2. Shifting the customer load in this manner would change power flow pattern in the Sacramento Area and would result in overloads, increased transmission line losses and unacceptable voltage drops in the Sacramento Area.

In order to correct these deficiencies:

1. The Rio Oso – Atlantic 230 kV line would need to be upgraded in advance of an upgrade otherwise required in 2015 at an estimated 2005 cost of $13.00 million.
2. The Rio Oso – Gold Hill 230 kV line would need to be upgraded by 2014 in advance of the 2026 need required if SMUD did not condemn the area at an estimated 2005 cost of $21.00 million.
3. In order to support voltages and reactive margin a shunt capacitor bank at an estimated 2005 cost of $11.00 million will be required at the Tesla substation unless SMUD can generate approximately 400 MW of generation at its Cosumnes Power Station. In order to be conservative, we assume SMUD will do so.

Based on a 2.0 percent annual cost escalation and using a 10 percent discount factor, severance damages as of January 1, 2008 amount to $14.12 million.

As shown in Table 7.3, fair market value including consideration of stranded investment and severance amounts to $565.88 million.

7.5 October 2008 Value

In the foregoing, we developed an estimate of fair market value as of January 1, 2008. We use this January 1 date because it represents the earliest date we anticipate that SMUD could acquire PG&E's property. In their July 29, 2005 application to LAFCo, SMUD assumes an acquisition in October 2008. In order to provide an estimate of value on October 1, 2008 we can extrapolate results shown in Table 7.3.

As shown in Table 7.3, the estimated increase in RCNLD over the 36 months beginning December 31, 2004 amounts to 10.79 percent ($382.66 million/$345.38million) or about 0.29 percent per month. Using this relationship, we expect the RCNLD value to increase by about 2.60 percent over the nine-month period beginning January 1, 2008. We therefore estimate the fair market value of the facilities identified by LAFCo in the July 17, 2005 letter to PG&E amounts to $528.84 million ($515.44 million * 1.026). After consideration of stranded investment and severance damages this amount increases to $580.60 million.

8.0 Critique of Beck and Staff Estimates

We prepared this report at PG&E's request in response to the potential condemnation of PG&E business properties located in certain areas of Yolo County, California. In connection with the potential condemnation, in January 2005, Beck in association with Stone & Webster Management Consultants, Inc. and Lucy & Company prepared a study entitled "Sacramento Municipal Utility District Annexation Feasibility Study". In this study, Beck ascribes a value to the facilities in the original area of $102 million. This value is based on a replacement cost new of $201 million less depreciation of $99 million.

Subsequently in April 2005, Staff prepared a study titled "Yolo Annexation Feasibility Study Staff's Assessment and Recommendations" in which Staff ascribes a value to the facilities in the original area of $130 million. This value is based on a replacement cost new of $245 million less depreciation of $115 million.

The Staff estimate of replacement cost new exceeds Beck by about 22 percent. Staff's value (RCNLD) exceeds Beck's by 13 percent.

As demonstrated above, there are substantial differences between the values estimated by Beck, Staff, and our value of $515.44 million before stranded investment. In the following, we will address major differences.

8.1 Beck

Table 8.1 compares, at a summary level, RCN and RCNLD as set forth in the Beck report, and our fair market value of $515.44 million ($345.38 million RCNLD as of December 31, 2004). In Table 9.8.1.1, we show this comparison in detail. In Table 9.8.1.2, we show a comparison of condition percent as of December 31, 2004 in detail.

As shown in Table 8.1, Beck finds an RCN value as of December 31, 2004 of about $201 million. This figure is 46 percent less than our RCN value as of December 31, 2004. Beck's RCNLD value of about $102 million is 30 percent less than our RCNLD value as of December 31, 2004 exclusive of going concern value, other assets, and liabilities.

Table 8.1
Summary Comparison of Fair Market Value
Beck versus Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line		Beck Case 4			B&V			Difference - Beck less B&V			
No.	Description	Quantity	Unit Cost	RCN	Quantity	Unit Cost	RCN	Not Included	Quantity	Unit Cost	RCN
			[D] / [B]	$ million		[G] / [E]	$ million	$ million	$ million	$ million	$ million
1	Transmission Plant										
2	Rights of Way	-	-	-	-	-	7.50	(7.50)	-	-	(7.50)
3	Transmission - miles	138	396,561	54.67	75.59	449,825	34.00	-	24.69	(4.03)	20.67
4	Total Transmission			54.67			41.50	(7.50)	24.69	(4.03)	13.17
5	Distribution Plant										
6	Rights of Way - parcels	-	-	-	2,300	7,000	16.10	(16.10)	-	-	(16.10)
7	Substations - MVA	405	66,179	26.82	386	94,928	36.64	3.68	(1.01)	(12.50)	(9.83)
8	Overhead Feeders miles	443	77,832	34.47	537	75,295	40.44	-	(11.61)	5.65	(5.96)
9	Underground Feeders - miles	260	108,030	28.05	354	522,996	184.89	(88.29)	(25.65)	(42.90)	(156.84)
10	Transformers - number	6,889	2,416	16.64	8,838	3,635	32.13	-	(5.79)	(9.69)	(15.48)
11	Low Voltage Circuits - miles	181	97,435	17.61	375	17,450	6.54	-	(16.94)	28.02	11.07
12	Service Drops										-
13	Overhead - number	40,682	324	13.19	45,017	280	12.60	-	(1.41)	2.00	0.59
14	Underground - number	-	-	-	24,239	1,021	24.75	(24.75)	-	-	(24.75)
15	Meters - number	40,681	149	6.07	70,000	105	7.34	-	(3.74)	2.47	(1.27)
16	Miscellaneous Equipment			5.51			36.32	(9.15)	(3.67)	(17.99)	(30.81)
17	Total Distribution			148.37			397.75	(134.61)	(69.82)	(44.96)	(249.38)
18	Total Transmission/Distribution			203.04			439.25	(142.11)	(45.12)	(48.99)	(236.22)
19	Davis Adjustment			(2.11)			-	(2.11)			(2.11)
20	Net RCN - as of 12/31/04			200.93			439.25	(144.22)	(45.12)	(48.99)	(238.33)
21	Composite Condition Percent			50.83%			78.63%				
22	RCNLD as of 12/31/04			102.14			345.38				(243.24)
											-
23	Other Elements of Value Due PG&E										-
24	Capital Additions (Section 5)						44.09				(44.09)
25	Change in Value - 12/31/2004 - 1/1/2008 (Section 5)						(6.82)				6.82
26	Going Concern Value (Section 6)						123.39				(123.39)
27	Other Assets (Section 7)						20.50				(20.50)
28	Liabilities (Section 7)						(11.11)				11.11
29	Total Fair Market Value as of 1/1/08						515.44				(413.30)

Notes
Col [G], Line 20: Davis substation not included in the above detail.
Line 28: Beck included in their RCNLD value a deduction for net salvage

We show in Table 8.1 the quantities and average unit costs underlying Beck's $102 million figure. In comparing results, we categorize differences into three components. The first component (Column H) relates to items that Beck or B&V do not include. Of the total difference in RCN of $238.33 million (Line 20), $144.22 million, or 61 percent, relates to facilities Beck failed to include any allowance for. Of the items Beck failed to include, we find that based on examination of Table 9.8.1.1, $88.29 million relates to Beck's failure to include an allowance for the cost of trenching or otherwise placing underground lines underground. Another $22.60 million relates to Beck's failure to include allowances for Transmission and Distribution Rights of Way, and $24.75 million relates to Beck's failure to include in its inventory 24,000 underground services.

In Column I of Table 8.1, we show differences attributable to differences in inventory quantity (number of units) where some allowance is included in both studies. As shown, differences due to quantity amount to about $45.12 million of which differences in the length of underground feeders accounts for about $25.65 million (see Table 9.8.1.1), and the length of low voltage circuits to nearly $14.96 million of the difference. While Beck's allowances are significantly below ours for these items, its allowance for transmission lines exceeds ours by about $24.69 million. Beck's greater allowance for transmission lines is due to Beck assuming SMUD will condemn substantially more transmission line than Staff or we do.

Differences in the average unit replacement cost (Column J) amount to approximately $48.99 million of the $238.33 million total difference. Significant differences in average unit costs are shown for, transmission lines, substations, underground lines, and line transformers. While Beck's allowances are significantly below ours for these items, its allowance for low voltage circuits exceeds ours by about $11.12 million.

8.2 Staff

Table 8.2 compares at a summary level, RCN and RCNLD as set forth in the Staff report, and our fair market value of $515.44 million ($345.38 million RCNLD as of December 31, 2004). In Table 9.8.2.1 we show the comparison of replacement cost new in detail and in Table 9.8.2.2 we show a comparison of condition percent in detail. As shown in Table 8.2, Staff finds a RCNLD value about $130.34 million (38 percent) less than we find. Staff's RCN value is about $193.96 million (56 percent) less than our value as of December 31, 2004, exclusive of going concern value, other assets, and liabilities.

Table 8.2
Summary Comparison Fair Market Value
Staff versus Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line		Staff			B&V			Difference - Staff less B&V			
No.	Description - Units	Quantity	Unit Cost	RCN	Quantity	Unit Cost	RCN	Not Included	Quantity	Unit Cost	RCN
			[D] / [B]	$ million		[G] / [E]	$ million	$ million	$ million	$ million	$ million
1	Transmission Plant										
2	Rights of Way	-	-	7.42	-	-	7.50	-	-	(0.08)	(0.08)
3	Transmission - miles	78	406,590	31.71	75.59	449,825	34.00	-	0.98	(3.27)	(2.29)
4	Total Transmission			39.13			41.50	-	0.98	(3.35)	(2.37)
5	Distribution Plant										
6	Rights of Way - parcels	159	3,508	0.56	2,300	7,000	16.10	-	(7.51)	(8.03)	(15.54)
7	Substations MVA	405	43,786	17.74	386	94,928	36.64	0.08	(0.06)	(18.92)	(18.90)
8	Overhead Feeders miles	416	76,720	31.95	537	75,295	40.44	(20.25)	(9.25)	21.01	(8.49)
9	Underground Feeders - miles	259	270,888	70.07	354	522,996	184.89	(88.29)	(25.70)	(0.83)	(114.83)
10	Transformers - number	6,009	2,886	17.34	8,838	3,635	32.13	-	(7.21)	(7.58)	(14.78)
11	Low Voltage Circuits - miles	180	81,607	14.72	375	17,450	6.54	-	(14.11)	22.29	8.18
12	Service Drops										-
13	Overhead - number	44,595	326	14.55	45,017	280	12.60	-	(0.14)	2.09	1.95
14	Underground - number	23,684	1,021	24.18	24,239	1,021	24.75	-	(0.57)	(0.00)	(0.57)
15	Meters - number	70,000	72	5.03	70,000	105	7.34	-	(0.04)	(2.27)	(2.32)
16	Miscellaneous Equipment			10.02			36.32	(16.32)	1.71	(11.69)	(26.30)
17	Total Distribution			206.16			397.75	(124.79)	(62.87)	(3.93)	(191.59)
18	Total Transmission/Distribution			245.30			439.25	(124.79)	(61.89)	(7.28)	(193.96)
19	Composite Condition Percent			53.14%			78.63%				
20	RCNLD as of 12/31/04			130.34			345.38				(215.04)
21	Other Elements of Value Due PG&E										
22	Capital Additions (Section 5)						44.09				(44.09)
23	Change in Value - 12/31/2004 - 1/1/2008 (Section 5)						(6.82)				6.82
24	Going Concern Value (Section 6)						123.39				(123.39)
25	Other Assets (Section 7)						20.50				(20.50)
26	Liabilities (Section 7)						(11.11)				11.11
27	Total Fair Market Value as of 1/1/08						515.44				(385.10)

Notes
Line 26: Staff included in their RCNLD value a deduction for net salvage

We show in Table 8.2 the quantities ascribed by Staff along with the average unit costs. In comparing results, we again categorize differences into three components. The first component (Column H) relates to items Staff or B&V do not include. Of the total difference in RCN of $124.79 million, or 64 percent relates to facilities Staff failed to include any allowance for. Of the items Staff failed to include, we find that based on examination of Table 9.8.2.1, $88.29 million relates to Staff's failure to include any allowance for the cost of trenching or otherwise placing underground lines underground.

In Column I of Table 8.2, we show differences attributable to differences in inventory quantity (number of units) where some allowance is included in both studies. As shown, differences due to quantity amount to $61.89 million, of which differences in the length of underground feeders account for about $25.70 million, the length of low voltage circuits for $14.11 million, and distribution rights of way $7.51 million.

Differences in the average unit replacement cost (Column J) amount to approximately $7.28 million of the $193.96 million total difference. Significant differences in average unit costs are shown for transmission lines, substations, and miscellaneous equipment. While Staff's allowances are significantly below ours for these items, its allowance for low voltage circuits exceeds ours by about $22.29 million.

8.3 Underground Feeders

8.3.1 Underground Feeder RCN

By far the single biggest difference between our replacement cost new (as of December 31, 2004) and Beck's (and Staff's) relates to underground feeders. In fact, nearly 59 percent of the difference between Staff's and our value relates to underground lines. Nearly 66 percent of the difference between Beck's and our value relates to underground lines. By far the biggest difference ($88.29 million) relates to Beck's and Staff's failure to include any consideration of the cost of trenching and paving, that is the cost to place underground lines underground. Another $25 million relates to the length of the underground lines in the area. In addition to these differences, Beck's unit cost of 12kv underground of $108,000 per mile is 60 percent below Staff's and our estimate of about $270,000 per mile (exclusive of trenching).

8.3.2 Trenching and Paving

Beck and Staff's failure to include any allowance for trenching and paving suggests that if SMUD were to build a new system in Yolo County some 260 miles of cable[40] PG&E

[40] Beck's and Staff's estimate.

has buried would lie unprotected on top of the ground. Their assumption is not only absurd, but is inconsistent with SMUD's practice of burying such cables in Sacramento.

As we discussed in Section 3, the fundamental underpinnings of valuation are the alternatives available to the buyer or seller. RCN measures the buyer's alternative of constructing a system which meets the same business needs as met by PG&E's existing system. One might argue that laying underground cable on top of the ground might serve the business needs of connecting line transformers to substations. However, because of safety and reliability, no rational person would do so.

We use a unit cost for trenching (including conduit, risers, and underground substructures of $249,750 per mile ($47.30 per foot). This unit cost falls well below the $60 plus per foot allowance SMUD relies on for budget purposes. In Appendix 8.3.2, we include copies of pages 221 and 222 of SMUD 2005 budget. On page 221, SMUD shows a unit cost of $61.028 per foot for trenching and conduit in unpaved areas and $69.844 per foot for trenching and conduit in paved areas. Had we used SMUD's unit cost for trenching we would have increased our RCN by about $25 million.

In short, Beck's and Staff's studies are flawed because they fail to consider the cost of placing underground cable underground.

8.3.3 Underground Feeder Unit Cost

We can test the reasonableness of RCN by examining the unit cost of constructing underground lines. In Table 8.1, we show Beck uses an average unit cost of $108,000 per mile ($20 per foot). In Table 8.2, we show Staff uses an allowance of $270,000 per mile ($51 per foot). As we show in these two tables, the unit cost we use is $523,000 per mile ($99 per foot)[41]. The issue then becomes, which (if any) of these three values $20, $50, or $100 per foot, is most reasonable?

In March 2005, Navigant Consulting, Inc. prepared a report for the Long Island Power Authority (LIPA) titled "A Review of Electric Utility Undergrounding Policies and Practices."[42] In this report, Navigant investigated the feasibility (cost effectiveness) of underground construction, including placing existing overhead facilities underground. Navigant makes several observations relevant to the issue of the cost of underground construction. Some of these observations include:

[41] As shown in Table 9.8.1.1 and Table 9.8.2.1 our total allowance includes $273,246 per mile ($51.75 per foot) for conductor and devices and $249,750 per mile ($47.30 per foot) for trenching, paving, and conduit.
[42] A complete copy of this 44 page (plus 6 page Executive Summary) report can be obtained from LIPA's website at http://www.lipower.org/pdfs/papers/underground-030805.pdf.

- Page ES-2 – "Cost estimates for underground construction are estimated at ten times the cost of overhead construction varying from $500,000 to several million dollars per mile."
- Page 4 – Navigant presents for 8 utilities, the underground construction cost per mile. For the utilities shown, costs range from $765,000 (Alleghany Power) to $1,826,000 (PEPCO) per mile.
- Page 4 – Navigant shows an average cost of $500,000 per mile for California.

Thus, the Navigant report suggests that our allowance of $523,000 per mile is well below costs shown for other utilities and consistent with the cost reported for California.

Our allowance of $523,000 per mile is also reasonably close to Navigant's observation that underground construction costs are ten times the cost of overhead. As shown in Tables 8.1 and 8.2, Beck, Staff, and B&V estimate the cost of overhead between $71,700 per mile (B&V) and $77,800 per mile (Beck). Using $75,000 per mile as the cost of overhead, our underground unit cost of $523,000 amounts to about 7 times that of overhead. This is certainly much closer to the 10 to 1 standard set forth in the Navigant Report than Staff's 3.6 times or Beck's 1.4 times.

As demonstrated above, our unit cost estimate of $523,000 per mile is clearly reasonable based on PG&E's experience, the experience of other utilities, and SMUD's budgeted cost.

Clearly the cost of underground construction is substantially above the cost of overhead. Based solely on economics, underground construction cannot be justified. That is the conclusion of the Navigant Report. However, very few customers will accept replacing existing underground lines with overhead. In fact, overhead customers seem to repeatedly request that the overhead lines be moved underground.

8.3.4 Underground Feeder Inventory

The other major difference in total underground cost relates to the overall length of underground feeders in the area. Beck and Staff estimate that within original area, PG&E has 260 miles (Staff 259) of underground feeder line. We find that based on the actual business records PG&E maintains in the normal course of business, and relies on in its day-to-day operation, maintenance, and planning activities, PG&E actually has over 350 miles of underground feeder lines. Furthermore, as we describe in Section 4.1 and demonstrated in tables 4.1.1 and 9.4.1.1, we tested the company's records and confirmed their accuracy by full field inspections of sample areas within the original area proposed to be condemned.

The issue is very simply, which inventory is more reliable? Beck and Staff both state they wanted the actual system records and admit their inventories are less accurate than if they had actual records to follow. Both Beck and Staff acknowledge limitations and expressed reservations in their respective reports of the accuracy of the inventory they rely on. For example, Beck states:

- Page 1-15: “Inventory includes the estimation”…
- Page 1-15: “The initial approach…by following each feeder and recording data…early on it was apparent that this approach was not sufficient.”
- P 1-19: “Due to its nature, inventorying underground distribution networks is significantly more difficult”…
- Page 1-19: …”it was not possible to gather the underground feeder routes directly from observation.”
- Page 1-19: …”it was not possible to observe the type of ducts and sizes of underground cables.”
- Page 1-19: “In several cases, it was necessary to conduct multiple searches in order to find underground transformers and/or underground switches.”
- Page 1-20: “Based on the information gathered in the field… a “possible distribution network layout” for underground areas….was developed.”
- Page 1-22: “In the case of underground networks, the information obtained from the field inventory was an estimation of a technically feasible underground network”...
- Page 1-22: …“the network shown utilizes all of the underground elements found, and it is in as much detail as it could be given the time and information available for this assignment.”
- Page 1-22: “The actual underground system represented in the AutoCAD drawings **might differ, in some cases, perhaps materially, from the actual grid.”** (emphasis added)

Similarly Staff states:

- Page 36: “The exact configuration of the underground system cannot be determined without PG&E’s maps for the system”…
- Page 36: “If spare facilities such as spare ducts or conductors in the underground system exist, these facilities would not be included in the estimate.”

Because of the lack of records, in order to estimate the inventory, Beck[43] extrapolated feeder lengths from an inventory of observed pad mounted and subsurface transformers and switches.[44] Based on the location of observed transformers and switches, underground feeder lengths were developed by a computer program based on manholes and other indicia of underground equipment Stone & Webster observed in the field. We understand the computer program draws a straight line between the two points, and Beck used this distance as the length of underground feeders.

As anyone familiar with an underground electric distribution system knows, feeders do not always go in a straight line between transformers, switches, etc., for a variety of reasons. There may be underground obstacles, or the feeders may be placed to take advantage of franchised rights-of-way or existing easements that do not travel a straight path. When underground distribution circuits change direction, equipment may or may not be in place to serve as a point in determining distance. In short, because of limitations in Beck's simplistic approach, the length of underground conductor will be understated.

We believe anyone objectively reviewing Beck's and Staff's estimated inventory must question its reasonableness in light of the above reservations noted by Beck and Staff in their respective reports. Further, one must question its reasonableness in light of Beck's failure to identify even one of about 24,000 underground services. One must ask, how complete is an inventory which concludes there are about 40,000 customers in an area that actually has about 70,000?

Beck did not prepare a full field inventory. We understand that during some public presentations, the impression was left that they may have done so. However, on pages 1-15 and 1-16 Beck clearly states that they estimated the distribution inventory by extrapolating results from a sample.

Staff at least recognized that Beck overlooked the underground services (see page 36 of the Staff report). As a result, Staff adopted PG&E's estimate available at the time Staff prepared its report. In light of the fact that PG&E's inventory for other elements of the system was developed relying on the very information that Staff stated PG&E did not provide Beck, Staff's adapting of Beck's estimate of the length of underground feeders (and rejection of PG&E's) becomes highly questionable. This failure on Staff's part suggests that had PG&E provided actual information, Beck or Staff would not have relied on it.

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[43] According to R.W. Beck, Stone & Webster is actually responsible for developing the inventory. See R.W. Beck Report, Executive Summary first page.

[44] SMUD Staff Report page 36.

The issue is not whether Beck and Staff made reasonable efforts to identify PG&E's equipment. The issue is whether the resultant inventory reasonably reflects PG&E's equipment actually in service. Based on the narrative set forth in the Beck report describing how Beck (or Stone & Webster) identified equipment, it appears they may have made a reasonable effort. The fact that they missed some equipment is expected. They acknowledge reservations concerning the limitations of the inventory developed.

Regardless of the reasonableness of Beck's and Staff's efforts, the fact remains that the inventory they develop does not include substantial quantities of PG&E's equipment. The inventory we develop herein overcomes this deficiency.

Based on the foregoing, we find that Staff has understated RCN in the original area SMUD proposes to condemn by $88.29 million due solely to its failure to include allowances for the cost of trenching underground feeders and understating the length of PG&E's underground system. Similarly, we find Beck understated RCN by this same amount, plus an additional $42.9 million due to its unreasonably low unit cost of underground conductor.

8.4 Rights of Way

Beck includes no allowances for land, easements or other land rights (rights of way). Staff includes allowance for only 159 parcels associated with PG&E's distribution system. Staff does include an allowance for transmission rights of way about equal to ours. Based on examination of PG&E's Electronic Document Center we identify 2,300 parcels related to distribution substations and lines in the original area. PG&E has 4 boxes of documents containing specifics for each of these parcels.

PG&E has obtained various rights to 2,300 parcels of land in the original proposed condemnation area. These rights were required in order to construct PG&E's systems. These rights are required in order for PG&E's existing system to occupy the land they rest on in order to legally access equipment to perform routine and emergency operation and maintenance activities. Clearly if SMUD wants to condemn PG&E's system, SMUD needs to acquire PG&E's rights to access the distribution system. SMUD's alternative - to condemn new rights from each landowner - would be even more expensive.

Notwithstanding SMUD's need, we believe that in the event SMUD pursues condemnation but does not condemn these rights of way and compensate PG&E for their value, upon transfer of ownership these assets (rights of way) become stranded, and as such PG&E is entitled to recover severance damages for their value.

Based on the foregoing, we find that Staff and Beck have understated RCN and RCNLD by $16 million and $24 million respectively.

8.5 Inventory

As shown in Tables 9.8.1.1 and 9.8.2.1 substantial differences in value are attributable to differences in quantities for overhead conductor, poles, and transformers in addition to underground feeders. As we earlier discussed, we tested the validity of the records we rely on by performing full field inventories for a number of areas.

8.5.1 Beck's Field Inventory

In addition to testing the reasonableness of the quantities we rely on, we compared the results of five of our full field inventories to the quantities developed by Beck for the same areas. Table 8.5.1 shows this comparison. In Figures 9.8.5.1 through 9.8.5.5, we show on maps prepared by Beck the location of equipment. On these maps Beck shows the location of equipment they identified. We have added to Beck's maps, the equipment that we identified that Beck missed. Consistent with Beck's color scheme we show equipment they identified in red. The equipment overlooked by Beck is shown in green and yellow.

Table 8.5.1
Comparison of Inventory
Beck vs Actual
Five Map Areas

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Beck	Actual	Missed	Percent Missed
					%
1	Transformers	154	206	52	25.24%
2	Switches	4	13	9	69.23%
3	KVA	10,597.5	15,608.0	5,010.5	32.10%

As shown in Table 8.5.1, Beck overlooked between 25 and 60 percent of the equipment actually in service. Relying on the drawings in Figures 9.8.5.1 through 9.8.5.5, anyone who wishes can go to the site and see the "missing" overhead and pad mounted equipment for themselves.

Staff's (and Beck's) failure to identify PG&E facilities extends across all distribution property as demonstrated in Table 8.5.2. As shown in Table 8.5.2, Beck and Staff inventories are deficient across the board, except for the Staff number of services and meters (which Staff appears to have adopted from PG&E).

We note in Table 8.5.2, some relatively modest differences between the Beck and Staff inventories. In our review of the Staff report, we are unable to identify Staff's reasoning for departure from the Beck amounts. The bulk of Staff's discussion of inventory goes to tests of reasonableness of inventory levels.

Table 8.5.2
Comparison of Inventory
Beck, Staff, and Actual

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Inventory			Understatement	
		Beck	Staff	Actual	Beck	Staff
					%	%
1	Overhead Conductor - mi	443	416	537	17.52%	22.46%
2	Poles - number	10,999	10,560	18,286	39.85%	42.25%
3	Underground Conductor - mi	260	259	354	26.56%	26.84%
4	Line Transformers - number					
5	Overhead	4,434	3,439	5,347	17.07%	35.68%
6	Pad Mount	1,489	1,601	2,104	29.23%	23.91%
7	Subsurface	966	969	1,387	30.35%	30.14%
8	Secondary - mi					
9	Overhead	56	55	134	58.47%	58.90%
10	Underground	125	125	240	48.00%	47.93%
11	Services - number					
12	Overhead	40,682	44,595	45,017	9.63%	0.94%
13	Underground		23,684	24,239	100.00%	2.29%
14	Meters	40,681	70,000	70,000	41.88%	0.00%
15	Switches - number	987	974	1,998	50.60%	51.25%
16	Capacitor Banks - number	189	185	212	10.85%	12.74%

The circularity of Staff's test of the reasonableness of inventory does not resolve the question of the credibility of either Beck's or Staff's inventory. Beginning on page 32 of its report, Staff presents a number of comparisons of the inventory in the original area proposed to be condemned with the number of pieces of comparable equipment over *SMUD's* entire system.

With regard to overhead conductor Staff concludes that "the rural area within Yolo County is heavily agricultural and lightly populated, resulting in lower amounts of overhead conductor being installed." Staff's reference to "lower amounts" relates to the ratio of circuit feet of line divided by service area square mile.[45]

With regard to overhead secondary, Staff said,

[45] We note that our inventory amounts to 537 miles of overhead or 2.83 miles per square mile. This 2.83 mile average is 16 percent below SMUD's system average of 3.37 miles per square mile. Our inventory level therefore meets Staff's test.

> "SMUD Staff thinks a reasonable estimate for the secondary length would be to double the length documented by Beck. Therefore, Staff used a length of 110.36 miles in its calculations."

As shown in Staff's Appendix E, page 38 of 40, however, Staff in fact used 55.18 miles in its calculation.

Staff's comparisons testing the reasonableness of its inventory appear predicated on the ratio of miles of primary line (underground and overhead) in SMUD's service area. We see however, no analysis testing the reasonableness of Staff's starting number in the comparisons. In Table 8.5.2.1, based solely on information set forth in the Staff report, we attempt to make such a comparison.

As shown in Table 8.5.2.1, in SMUD's territory the average length of feeders (overhead and underground) amounts to over 75 feet per customer. Staff's RCN calculation for the area proposed to be condemned are based on about 50 feet per customer. We are unaware of any reason to believe that the average distance of feeders in the proposed area is less than the SMUD average, especially in light of Staff's observation regarding the agricultural and lightly populated character of the area. In short, Staff's estimate of value has no credibility. Based on our inventory of 537 and 354 miles of overhead and underground primary, our allowance amounts to 67 feet per customer. This allowance, though still below the SMUD system average, certainly appears more reasonable than Staff's 50 feet.

Table 8.5.2.1
Comparison of Primary Lines
SMUD vs. Proposed Annexation Area

Line No.	[A] Description - Units	[B] SMUD	[C] Proposed Area
1	Number of Customers[1,2]	583,000	70,000
2	Primary Lines - miles		
3	Overhead[3]	3,036.8	416.30
4	Underground[4]	5,530.0	259.65
5	Total Primary	8,566.8	675.95
6	Average - feet/cust.	77.59	50.99

(1) Staff Report P.57 SMUD's customer base will increase 12% - 70,000 / 12% = 583,000 SMUD customer base
(2) Staff Report P.36
(3) Staff Report P.33
(4) Staff Report P.37

8.6 Underground Services

We previously (in Section 8.3) addressed Beck's failure to include any value for approximately 24,000 underground services. Thus, we find Beck has understated RCN by about $25 million. Staff includes a value about equal to ours.

8.7 Low Voltage Circuits

Overall Beck's and Staff's RCN allowance for low voltage circuits exceeds ours. While as an overall component of the total proposed condemnation area we do not attribute a significant amount of value to low voltage circuits, the differences between Beck, Staff, and our data are quite substantial.

We have previously discussed limitations in connection with the inventory developed by Beck and relied on in part by Staff. We have also described the extensive records which underlay the inventory we develop. Consistent with their inventory of other equipment Beck and Staff have significantly understated the amount of overhead and underground secondary lines. Though our inventory level for secondary circuits exceeds Beck's and Staff's, Beck and Staff used substantially higher unit costs than we do. We have not been able to identify the factors contributing to these substantially higher unit costs.

8.8 Transmission Lines

We develop the unit cost for transmission lines including conductor, poles, and towers based on engineering drawings showing detailed specifications for each line section and the current engineering cost estimates. In reviewing Beck's and Staff's unit cost for transmission lines we see no allowance for the substantial investment required in towers of sufficient height and strength. As we demonstrate in Section 4.2.2, PG&E has a substantial transmission infrastructure in the area including extensive transmission towers and poles.

Since transmission towers are relatively few in number, and are the most visible and valuable of the individual pieces of equipment under analysis (except for some substation equipment), we would have thought Beck and Staff would come reasonably close to their actual count and height in the area studied. Surprisingly, that is not the case. Staff does not attempt to determine today's cost of PG&E's system facilities, instead electing to use broad general unit costs. The unit costs Staff uses are:

Conductor	$200,879 per circuit mile
Steel Poles	$166,578 per line mile
Lattice Tower	$149,845 per line mile

Wood Poles $137,256 per line mile

The above unit costs conflict with conventional wisdom. Conventional wisdom holds that wood pole construction is less costly than steel poles and that steel poles are less costly than lattice towers. Staff suggests that the cost of lattice tower construction is about 10 percent less than steel poles. We show photos of these various types of structures in Figures 4.2.2.1, 4.2.2.2, and 4.2.2.3 respectively. Even cursory examination of these photos calls into question the suggestion that lattice towers are less costly than steel poles.

With regard to PG&E's transmission system in the area, Beck alleges that the PG&E transmission system has many undersized facilities (Beck Report page 1-5) and that PG&E's planning criteria were not made available to the Project team (Beck Report page 1-3). PG&E is a part of the California Independent System Operator (CAISO) control area. As such, PG&E plans its transmission system in accordance with the CAISO Grid Planning Criteria. These Criteria are used throughout the CAISO control area, and as such were (and are) available to Staff and the public on the CAISO's website. Based on the short description of SMUD's "Reliability Criteria for Transmission System Planning" (see Beck Report page 1-3) SMUD's criteria are very similar to the CAISO Grid Planning Criteria.

PG&E's transmission system in the area is not undersized. As a Participating Transmission Owner (PTO) in the CAISO control area, PG&E assesses its transmission system annually looking out at least the next 5 years to ensure adequate transmission capacity to supply forecasted loads consistent with the CAISO Grid Planning Criteria. The assessment and subsequent development of the proposed transmission upgrades that make up the Expansion Plan are performed in a public stakeholder process. The current 2004 Assessment and Expansion Plan is available upon request. Not all assumptions made in the Beck report on PG&E's transmission expansion plans are accurate.

The fact that PG&E's transmission capacity is adequate does not mean that PG&E's lines have capacity sufficient to meet requirements in the area proposed to be condemned under the reconfigured power flows accompanying a takeover of PG&E's system by SMUD. PG&E's transmission system is not designed to accommodate the power flows incident to operation of the system as envisioned by Beck and Staff. Any deficiency in PG&E's transmission system to accommodate power flows in the event of a SMUD takeover does not detract from value.

8.9 Substations

As shown in Tables 9.8.1.1 and 9.8.2.1, with regard to substations the most significant difference in RCN between Beck, Staff and Black & Veatch relates to the West Sacramento Substation. We show the layout and principal equipment in this substation in Table 9.4.2.3.1.

As shown in this Table, in the equipment list and the single-line diagram, the West Sacramento Substation is equipped with two 30 MVA and one 45 MVA transformers for a total capacity of 105 MVA. Beck and Staff both reflect only 90 MVA of transformer capacity. West Sacramento also has a ring switch bus, in order to switch between transmission feeders and two sets of transmission capacitor banks, and a control building. This ring switch bus adds considerably to value through the added capability and flexibility offered.

8.10 Line Transformers

As shown in Table 8.5.2, both Beck and Staff understated transformer inventory by about 30 percent. However, their understatement is not limited to numbers of transformers, they also significantly understate the capacity of the transformers in the area. For example in Table 8.10, we show for PG&E's map L-18-16 a comparison of the number of transformers and the capacity included in the Beck Study with the actual number of transformers and capacity.

Table 8.10
Pacific Gas and Electric Company
Comparison of Number and Capacity of Line Transformers
Beck versus Actual
PG&E Map L-18-16

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Type	Number	Average KVA	Total KVA	Understatement
1	Beck	Subsurface	25	50.0	1,250	37.5%
2	Beck	Overhead	2	32.5	65	60.6%
3	PG&E	Subsurface	25	80.0	2,000	
4	PG&E	Overhead	3	55.0	165	

As shown above in this map area Beck's count of transformers is approximately correct however, on average it understates the size (capacity) by about 40 percent. This understatement is not unexpected in light of Beck's statement on page 1-18 of its report that,

> "In many cases, overhead distribution transformers capacity could not be read, making it almost impossible to get their exact capacity. In these cases, the capacity was estimated by comparison with other units of similar size whose capacity was known… However, there remains the possibility of discrepancy between estimates and the real capacity."

PG&E's records and field inspection show that Beck and Staff understated both the number of distribution transformers and the capacity of transformers included in their inventory. The number of transformers included in Staff inventory is below Beck's making it even more inadequate. Further comparisons of the number and total capacity included by Beck in its inventory with actual is shown in Table 9.8.5.1.

8.11 Miscellaneous Equipment

Our RCN for miscellaneous equipment amounts to about $36 million which exceeds the amounts included by Beck and Staff of $30 million and $25 million respectively. In addition to not including all of the equipment used by PG&E to provide service to customers in the original area proposed to be condemned, Beck and Staff understate the current unit cost.

8.12 Depreciation

As shown in Tables 8.1.1 and 8.2.1, our allowance for depreciation differs substantially from the allowance included by Beck and Staff. We provide additional detail in Tables 9.8.1.2 and 9.8.2.2.

We find overall a composite condition of 78.63 percent as compared to 50.83 percent by Beck and 53.14 percent by Staff. One difference between our condition percent and Beck's and Staff's relates to the treatment of net salvage (cost of removal). First, Beck and Staff overstate net salvage by applying to RCN a percentage developed by and intended for use with original cost to RCN. Second, they both fail to recognize that any liability for net salvage will not occur until the facilities are actually removed from service years after the valuation date. As we discuss in Section 7.2, we have reduced value by $11.11 million (January 1, 2008 valuation date) to reflect the present value of the net salvage liability.

The second major factor contributing to the difference in condition relates to the present worth factor embodied in the calculation. We use a 6.25 percent present worth factor as we discussed in section 4.7. Beck and Staff use a zero factor, commonly referred to as straight-line depreciation. We describe in Section 4.3 the rationale for using a 6.25 percent factor as opposed to the zero factor used by Beck and Staff.

8.13 Other Elements of Value

As shown in Tables 8.1 and 8.2, and as described in Section 5, 6, and 7, we include in our total value (as of January 1, 2008) allowances for price level change, retirements, and reduced condition between December 31, 2004 and January 1, 2008, additions and replacements for the three-year period (2005, 2006, and 2007), going concern value, and current assets and liabilities. With the exception of liabilities, which we describe above, Beck and Staff include no consideration for these real elements of value.

8.14 Conclusion

Based on our analysis of the Beck and Staff reports, we find that both contain serious flaws in connection with their development of the fair market value of PG&E's facilities in the original area proposed to be condemned. These flaws contribute to a substantial and material understatement of the fair market value which SMUD should reasonably expect a condemnation court will require SMUD to pay for PG&E's property SMUD proposes to take. These understatements of value relate to:

- Failing to include all PG&E equipment
- Understating the current unit cost to replace equipment
- Overstating depreciation by:
    - Failing to recognize the value of property over time (present worth depreciation)
    - Improperly calculating net salvage
    - Failing to consider any cost attributable to net salvage will not occur until the future
- Failing to recognize that the valuation date under any reasonable set of assumptions will not occur until at least January 1, 2008
- Failing to recognize the fair market value of other assets incidental to a taking by SMUD

9.0 Detailed Tables

Table 9.4.1.1
Pacific Gas and Electric Company
Reconciliation of Transmission Lines in Proposed Condemnation Area
SMUD Staff vs. Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[N]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
			SMUD Staff		B&V - PG&E LINE Diagrams - Line Segment - Current Miles																		
Line No.	Description		Linear Miles	Circuit Miles	Total	A	B	C	D	E	F	G	J	K	L	M	N	O	P	Q	R	S	T
	Included by SMUD Staff																						
1	W. Sacramento-Deepwater Tap 2		1.04	2.08	2.08				1.04	1.04													
2	Deepwater Tap 2-Hurley		5.00	5.00	5.00				5.00														
3	North City-Tap 2		5.00	5.00	5.00					5.00													
4	Deepwater Tap 1-West Sacramento		1.76	1.76	1.58		1.58																
5	Deepwater Tap 1-Davis		10.89	10.89	9.74		9.74																
6	Deepwater Tap 1&2-Deepwater		2.39	4.78	4.67						2.28	2.39											
7	P.O. Tap-Post Office		0.66	0.66	0.66										0.66								
8	Davis-Barker Jct		9.85	9.85	9.80	9.80																	
9	Barker Jct-Close to Elder Creek		15.96	15.96	16.10	16.10																	
10	Close to Elder Creek-Brighton	Stranded	2.50	2.50	2.50																		2.50
11	Davis-Hunt Tap		1.09	1.09	1.02			1.02															
12	Hunt Tap-Woodland Bio Mass		9.04	9.04	9.04			9.04															
13	Woodland Bio-Mass Woodland		1.52	1.52	1.56			1.56															
14	HuntTap-Hunt		0.06	0.06	0.18											0.18							
15	Woodland-Close to County Rd 18c		2.50	5.00	5.00														2.50	2.50			
16	Woodland Poly Tap-Woodland Poly		0.31	0.31	0.30									0.30									
17	Close to County Rd 18c-Rio Oso Tap	Stranded	8.16	16.32	16.32														8.16	8.16			
18	Total		77.73	91.82	90.55	25.90	11.32	11.62	6.04	6.04	2.28	2.39	-	0.30	0.66	0.18	-	-	10.66	10.66	-	-	2.50
19	Lines Omitted by SMUD Staff																						
20	Bio Mass Tap				0.86								0.86										
21	Plainfield Tap				3.00												3.00						
22	West Sacramento-Brighton	Stranded			6.47																6.47		
23	West Sacramento-Rio Oso	Stranded			6.63																	6.63	
24	Rio Oso-West Sacramento	Stranded			29.67													29.67					
25	Total Omitted				46.63																		
26	Gross Total				137.18	25.90	11.32	11.62	6.04	6.04	2.28	2.39	0.86	0.30	0.66	0.18	3.00	29.67	10.66	10.66	6.47	6.63	2.50
27	(Less Stranded)				(61.59)				-									(29.67)	(8.16)	(8.16)	(6.47)	(6.63)	(2.50)
28	Net Total				75.59	25.90	11.32	11.62	6.04	6.04	2.28	2.39	0.86	0.30	0.66	0.18	3.00	-	2.50	2.50	-	-	-

Table 9.4.1.2
Pacific Gas and Electric Company
Detailed Comparison
Of 8 Random Field Inventories

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
		Location	Davis			West Sacramento			Woodland		
Line No.	Description	Map No.	L-18-16	M-19-14	M-18-13	N-21	L-23-24	L-22-10	J-18-02	J-17-06	Total
1	CEDSA										
2	OH Conductor - line ft.		-	11,276	11,040	5,248	18,140	-	9,720	3,389	58,812
3	UG Conductor - line ft.		8,384	2,417	3,284	-	142	11,701	4,720	20,051	50,698
4	OH Transformers - number		2	9	30	25	41	-	13	22	142
5	UG Transformers - number		25	7	9	-	-	20	16	55	132
6	Poles - number		8	35	69	75	193	-	39	50	469
7	Measured on Map										
8	OH Conductor - line ft.		1,704	12,296	10,236	13,640	13,658	-	5,553	4,839	61,926
9	UG Conductor - line ft.		14,500	2,271	2,473	-	362	14,330	3,364	21,966	59,266
10	OH Transformers - number		3	9	30	22	39	-	12	23	138
11	UG Transformers - number		24	7	14	-	-	21	16	54	136
12	Poles - number		8	30	81	74	189	-	37	48	467
13	Difference (CEDSA - Map)										
14	OH Conductor - line ft.		(1,704)	(1,020)	804	(8,392)	4,482	-	4,167	(1,450)	(3,114)
15	UG Conductor - line ft.		(6,116)	146	811	-	(220)	(2,629)	1,356	(1,915)	(8,568)
16	OH Transformers - number		(1)	-	-	3	2	-	1	(1)	4
17	UG Transformers - number		1	-	(5)	-	-	(1)	-	1	(4)
18	Poles - number		-	5	(12)	1	4	-	2	2	2
19	Excess (CEDSA over Map) %										
20	OH Conductor - line ft.		-100.0%	-8.3%	7.9%	-61.5%	32.8%	0.0%	75.0%	-30.0%	-5.0%
21	UG Conductor - line ft.		-42.2%	6.4%	32.8%	0.0%	-60.9%	-18.3%	40.3%	-8.7%	-14.5%
22	OH Transformers - number		-33.3%	0.0%	0.0%	13.6%	5.1%	0.0%	8.3%	-4.3%	2.9%
23	UG Transformers - number		4.2%	0.0%	-35.7%	0.0%	0.0%	-4.8%	0.0%	1.9%	-2.9%
24	Poles - number		0.0%	16.7%	-14.8%	1.4%	2.1%	0.0%	5.4%	4.2%	0.4%

Figure 9.4.1.1
Pacific Gas and Electric Company
Map of 9 Representative Areas

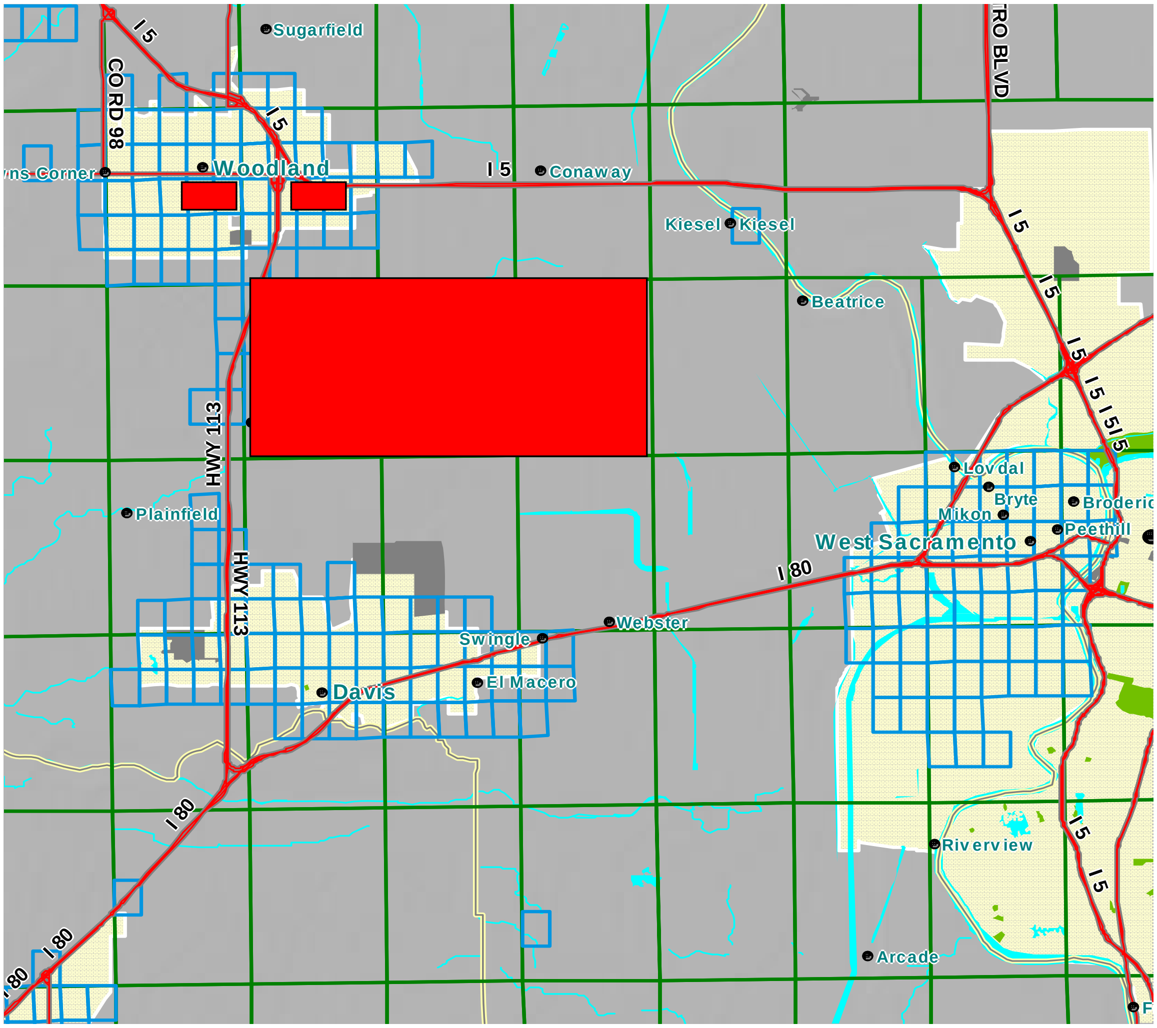


Table 9.4.1.3
Pacific Gas and Electric Company
Summary of 9
Representative Field Inventories

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Number of Units: CEDSA	Map	Difference	Excess %
1	OH Conductor	181,458	178,435	3,023	1.7%
2	UG Conductor	44,422	36,628	7,794	21.3%
3	OH Transformers	350	346	4	1.2%
4	UG Transformers	108	100	8	8.0%
5	Poles	1,083	1,005	78	7.8%

Note: Map area J-18-13 - C-EDSA database included facilities associated with projects which had not yet been recorded in PG&E's plat map.

Table 9.4.1.4
Pacific Gas and Electric Company
Detailed Comparison
Of 9 Representative Field Inventories

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
Line No.	Description	Map No.	J-17-14	J-17-15	J-18-13	J-18-14	K-18	K-18-01	K-18-06	K-19	K-21	Total
1	CEDSA											
2	OH Conductor - line ft.		21,343	25,278	672	5,072	57,107	6,700	-	61,390	3,897	181,458
3	UG Conductor - line ft.		460	3,121	20,473	18,256	1,888	-	-	224	-	44,422
4	OH Transformers - number		99	98	4	2	85	5	8	29	20	350
5	UG Transformers - number		4	10	47	45	1	-	-	1	-	108
6	Poles - number		276	231	8	21	299	12	8	142	86	1,083
7	Measured on Map											
8	OH Conductor - line ft.		20,850	20,332	690	1,476	68,093	2,847	2,229	41,403	20,515	178,435
9	UG Conductor - line ft.		-	2,968	15,198	18,372	-	-	-	90	-	36,628
10	OH Transformers - number		98	104	4	-	80	1	8	31	20	346
11	UG Transformers - number		-	9	47	43	-	-	-	1	-	100
12	Poles - number		264	224	6	4	271	13	7	136	80	1,005
13	Difference (CEDSA - Map)											
14	OH Conductor - line ft.		493	4,946	(18)	3,596	(10,986)	3,853	(2,229)	19,987	(16,618)	3,023
15	UG Conductor - line ft.		460	153	5,275	(116)	1,888	-	-	134	-	7,794
16	OH Transformers - number		1	(6)	-	2	5	4	-	(2)	-	4
17	UG Transformers - number		4	1	-	2	1	-	-	-	-	8
18	Poles - number		12	7	2	17	28	(1)	1	6	6	78
19	Excess (CEDSA over Map) %											
20	OH Conductor - line ft.		2.4%	24.3%	-2.6%	243.6%	-16.1%	135.3%	-100.0%	48.3%	-81.0%	1.7%
21	UG Conductor - line ft.		0.0%	5.2%	34.7%	-0.6%	0.0%	0.0%	0.0%	149.1%	0.0%	21.3%
22	OH Transformers - number		1.0%	-5.8%	0.0%	0.0%	6.3%	400.0%	0.0%	-6.5%	0.0%	1.2%
23	UG Transformers - number		0.0%	11.1%	0.0%	4.7%	0.0%	0.0%	0.0%	0.0%	0.0%	8.0%
24	Poles - number		4.5%	3.1%	33.3%	425.0%	10.3%	-7.7%	14.3%	4.4%	7.5%	7.8%

Note: Map area J-18-13 - C-EDSA database included facilities associated with projects which had not yet been recorded in PG&E's plat map.

Figure 9.4.1.2
Pacific Gas and Electric Company
System Components

Transmission Lines:

- Towers and fixtures
- Poles and fixtures
- Overhead conductors and devices
- Underground conduit (none)
- Underground conductors and devices (none)
- Rights of Way

Distribution Substations

- West Sacramento, Deepwater, Davis, Woodland, and Plainfield
- Land and Land Rights
- Structures and Improvements
- Station Equipment

Distribution Overhead:

- Rights of Way
- Poles and associated hardware including cross arms, brackets and insulators
- Conductor, typically either 2 wires for single phase or 3 wires for three phase circuits. Conductor size ranges from #2 copper to 750 Al for larger feeder circuits.
- Transformers
- Miscellaneous line equipment including capacitors, reclosers, switches, etc.
- Services

Distribution Underground:

- Rights of Way
- Conduits
- Conductor
- Transformers (padmount and subsurface)
- Miscellaneous line equipment including padmount and subsurface switches, capacitors, reclosers, etc.
- Services

Meters

Figure 9.4.2
Summary of Black & Veatch
Inventory and Valuation Methodology

- Rights of Way
  - We consulted professionals in PG&E’s Land Department for the current market value of the specific transmission and distribution land rights. PG&E’s Land Department professionals are responsible for acquiring the land and land rights required by PG&E.
  - We include in the cost an allowance for administrative work, including property owner records, document preparation, acquisition/negotiation, necessary survey work, and compensation to the owner.
  - We do not include any costs incurred in connection with acquiring any needed permits. These costs are included in RCN of equipment.
- Transmission Lines
  - We consulted engineering drawings of the transmission lines SMUD proposes to condemn to determine the size and configuration of components in service.
  - PG&E’s engineering department professionals develop RCN based on PG&E’s current construction costs.
- Substations
  - We consulted facility engineering drawings and field substation operations personnel to determine equipment inventory.
  - We develop values from PG&E standard costs.
- OH Circuits – Conductor
  - We develop the total circuit length from PG&E’s C-EDSA database.
  - We develop a single unit cost applicable to all sizes.
- OH Conductor
  - We develop total circuit length from the PG&E’s C-EDSA database.
  - We develop one unit cost for all sizes of conductor to determine value.
- Poles
  - We develop pole lengths and quantities from PG&E's C-EDSA data base, adjusted to reflect poles no included in this database.
  - We develop values material and labor prices from PG&E's estimating program.
- UG Circuits
  - We rely on PG&E's C-EDSA database to determine the total length of UG feeder circuits.
  - We develop one unit cost for all sizes.

Figure 9.4.2 (Continued)

Summary of Black & Veatch

Inventory and Valuation Methodology

- We develop unit cost based on cost levels for brown construction.
- We include the value of pole risers with UG conductor.

- OH Transformers
  - We develop transformer capacity and quantity from PG&E’s C-EDSA data field.
  - We develop values using material and labor prices from PG&E’s estimating program.
- UG Transformers
  - We develop transformer capacity and quantity from PG&E's C-EDSA database.
  - We develop values using material and labor prices from PG&E's estimating program
- Service Drops
  - We set the total number of service drops equal to the number of customers and percentage of OH vs. UG circuit feet.
  - We split services between OH and UG in the same proportions as the circuit length of OH and UG feeders.
  - We estimate RCN based on an overall standard footage for each service.
- Switches and Other Miscellaneous Equipment
  - We use PG&E's C-EDSA database and PG&E's Engineering Planning Group develop the total quantity of switches.
  - We use PG&E's Planning Engineering unit costs to develop RCN.
- Capacitor Banks
  - We rely on PG&E's C-EDSA database and PG&E's Engineering Planning Group to determine the total quantity of capacitor banks.
  - We rely on PG&E's Planning Engineering unit costs to develop cost to install the equipment.
- Voltage Regulators
  - We use PG&E's C-EDSA database and PG&E's Engineering Planning Group to determine the total quantity of voltage regulators and boosters
  - We use PG&E's Planning Engineering unit costs to develop cost to install the equipment.

Table 9.4.2.2
Pacific Gas and Electric Company
Transmission Lines SMUD Proposes to Condemn
RCN as of December 31, 2004

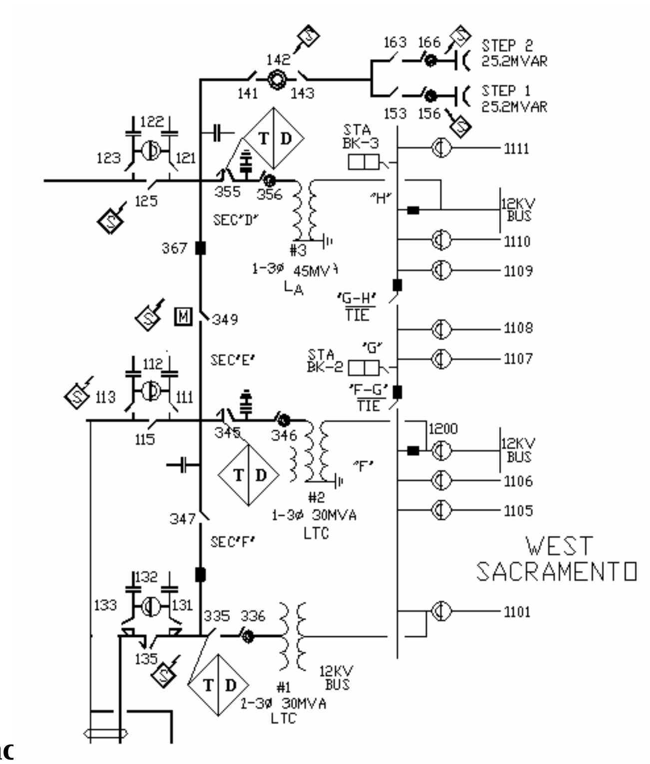
	[A]	[B]	[C]	[D]	[E]
Line No.	Line	Description	Quantity	Unit Cost	RCN
	(1)			$	$ Million
1	A	Brighton Davis (25.90 Miles)			
2		Segment 1			
3		336.4ASCR (16.10 Miles)	253,123	6.33	1.60
4		Towers	110	100,000	11.00
5		Segment 2			
6		715 AL-Wood Poles (9.28 miles)	147,746	10.03	1.48
7		Wood Poles	194	5,039	0.98
8		Segment 3			
9		715 Al-Tubular Steel (.52 miles)	8,278	10.03	0.08
10		Tube Steel Poles	5	65,000	0.33
11		Total Cost			15.47
12	B	West Sacramento-Davis 115kV (11.32 miles)			
13		Segment 1			
14		715 Al - Wood Poles (1.55 miles)	27,978	10.03	0.28
15		65' Wood Poles	30	5,039	0.15
16		Segment 2			
17		4/0 Al - Towers (.03 miles)	475	6.33	0.00
18		85' Steel Towers	2	250,000	0.50
19		Segment 3			
20		2/0 Cu - Wood Poles (9.74 miles)	154,244	5.13	0.79
21		65' Wood Poles	202	5,039	1.02
22		Other Equipment			
23		Transmission Switch	2	4,355	0.01
24		Total Cost			2.75
25	C	Woodland - Davis (11.62 miles)			
26		Segment 1			
27		715 Al - Towers (1.02 miles)	16,181	10.03	0.16
28		Towers	2	111,177	0.22
29		Segment 2			
30		715 Al - Wood Poles (10.60 miles)	168,154	10.03	1.69
31		65' Wood Poles	193	5,039	0.97
32		Total Cost			3.04
33	D&E	West Sac - Rio Oso (Tower 13/095) (12.08 miles)			
34		397.5 Al (12.08 miles)	204,969	6.33	1.30
35		Towers	25	75,000	1.88
36		Towers	10	90,000	0.90
37		Towers	27	60,000	1.62
38		Towers	2	180,000	0.36
39		257' Steel Towers	2	400,000	0.80
40		Total Cost			6.85
41	F&G	Deepwater Tap #1 & #2 (4.67 miles)			
42		397 Al (4.02miles)	63,676	6.33	0.40
43		715 Al (0.65 miles)	12,038	10.03	0.12
44		85' Tube Steel Poles	22	65,000	1.43
45		257' Steel Towers	2	400,000	0.80
46		Transmission Switches	2	4,355	0.01
47		Total Cost			2.76
48	J	Woodland Biomass Tap (0.86 miles)			
49		4/0 Al (0.86 miles)	13,630	6.33	0.09
50		65' Wood Poles	16	5,039	0.08
51		Transmission Switch	1	4,355	0.00
52		Total Cost			0.17
53	K	Woodland Poly Tap (0.3 miles)			
54		4/0 Al (0.3 miles)	4,695	6.33	0.03
55		65' Wood Poles	7	5,039	0.04
56		Transmission Switch	1	4,355	0.00
57		Total Cost			0.07
58	L	US Post Office Tap (0.66 miles)			
59		397.5 Al (0.66 miles)	10,800	6.33	0.07
60		65' Wood Poles	14	5,039	0.07
61		Transmission Switch	1	4,355	0.00
62		Total Cost			0.14
63	M	Wesson Hunt Tap (0.18 miles)			
64		715 Al (0.18 miles)	3,000	10.03	0.03
65		65' Wood Poles	4	5,039	0.02
66		Transmission Switch	1	4,355	0.00
67		Total Cost			0.05
68	N	Plainfield Tap (3.0 miles)			
69		4/0 Al (3.00 miles)	44,352	6.33	0.28
70		65' Wood Poles	36	5,039	0.18
71		Total Cost			0.46
72	O	Rio Oso - West Sac. (29.67 miles)			
73		397 Al (29.67 miles)	469,973	6.33	2.97
74		Towers	212	100,000	21.20
75		Total Cost			24.17
76	P&Q	Rio Oso - Woodland #1 & #2 (21.32 miles)			
77		715 AL	335,808	10.03	3.37
78		Towers	61	100,000	6.10
79		Total Cost			9.47
80		Total Stranded (16.32 mi. - 76.55%)			7.25
81		Total Not Stranded (5 mi. - 23.45%)			2.22
82	R&S	West Sac to Tower 13/095 (13.10 miles)			
83		715 AL (13.10 miles)	198,000	10.03	1.99
84		Towers	20	75,000	1.50
85		Towers	20	90,000	1.80
86		Total Cost			5.29
87	T	Brighton Davis (2.5 miles)			
88		336.4 ACSR	39,600	6.33	0.25
89		Towers	22	100,000	2.20
90		Total Cost			2.45
91		Total (miles)	137.18		73.16
92		Stranded	61.59		39.16
93		Not Stranded	75.59		34.00

(1) Lines O through T are stranded with the exception of 2.50 miles on P and Q.

Figure 9.4.2.3.1
West Sacramento Substation

Equipment

- Two 115/12 kV, 30 MVA, 3-phase banks
- One 115/12 kV, 45 MVA, 3-phase bank
- Three 12 kV bank breakers
- Seven 12 kV feeder breakers
- 12 kV structure
- Two transmission capacitors
- Other



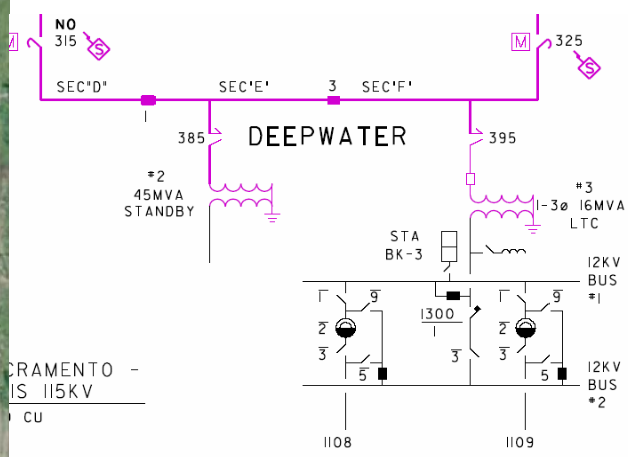
Site Occupies 3.07 ac

Figure 9.4.2.3.2
Deepwater Substation

Equipment

- One 115/12 kV, 16 MVA, 3-phase bank
- Two 12 kV feeder breakers
- 12 kV structure
- One control building
- Other

- **A new 45 MVA tramsformer became operational in July 2005.**

Site Occupies 5.95 acres

Figure 9.4.2.3.3
Woodland Substation

Equipment

- One 115/12 kV, 30 MVA, 3-phase bank
- Two 115/12 kV, 45 MVA, 3-phase banks
- Three 12 kV bank breakers
- Twelve 12 kV feeder breakers
- 12 kV structure
- One control building
- Other

Aerial Photo Woodland Substation

Site occupies 2.92 acres

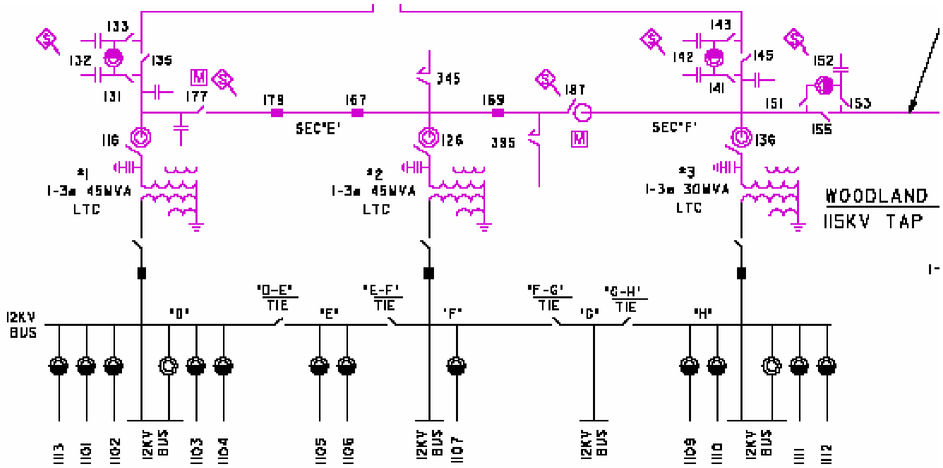


Figure 9.4.2.3.4
Davis Substation

<u>Equipment</u>

- Three 115/12 kV, 45 MVA, 3-phase banks
- Two 12 kV bank breakers
- Eleven 12 kV feeder breakers
- 12 kV structure
- Other

Site occupies 1.93 acres

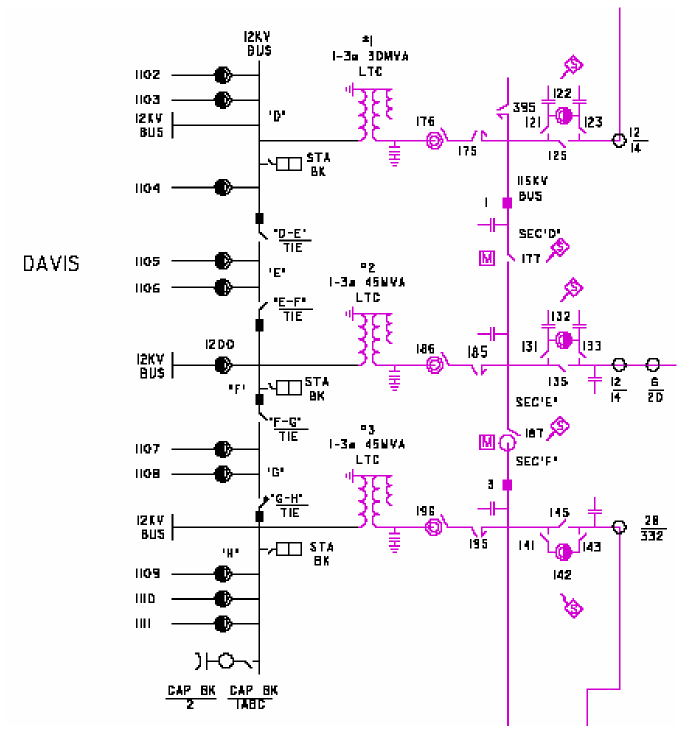
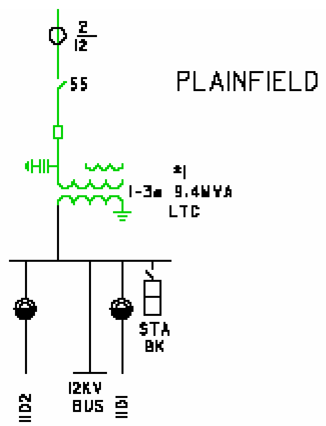


Figure 9.4.2.3.5
Plainfield Substation

Equipment

- One 60/12 kV, 9.4 MVA, 3-phase bank
- Two 12 kV feeder breakers
- 12 kV structure
- One control building
- Other

Aerial Photo Plainfield Substation



Site occupies 0.91 acres

Table 9.4.2.4
Pacific Gas and Electric Company
RCN

	[A]	[B]	[C]	[D]
Line No.	Description - Units	As of December 31, 2004		
		Quantity	Unit Cost	RCN
			$	$ million
1	TRANSMISSION			
2	Land and Rights of Way		-	7.50
3	Transmission Lines- miles	75.59	449,825	34.00
4	TOTAL TRANSMISSION	75.59	549,044	41.50
5	DISTRIBUTION			
6	Land and Rights of Way	2,300	7,000	16.10
7	Substations - MVA			
8	West Sacramento	105	137,310	14.42
9	Deepwater	16	210,272	3.36
10	Davis	135	65,401	8.83
11	Woodland	120	74,865	8.98
12	Plainfield	10	104,738	1.05
13	Total Substations	386	94,928	36.64
14	Overhead Conductors and Devices - miles			
15	12kv Overhead	537	37,589	20.19
16	Poles - number	18,286	1,107	20.25
17	Total Overhead	537	75,295	40.44
18	Underground Conductors and Devices - miles			
19	12kv Underground	354	273,246	96.60
20	Trenching - miles	354	249,750	88.29
21	Total Underground - miles	354	522,996	184.89
22	Transformers - number			
23	Overhead	5,347	1,514	8.09
24	Underground			
25	Pad Mount	2,104	6,500	13.68
26	Subsurface	1,387	7,466	10.36
27	Total Underground	3,491	6,884	24.03
28	Total Transformers	8,838	3,635	32.13
29	Secondary (Low Voltage Circuits) - miles			
30	Overhead	134	10,877	1.46
31	Underground	240	21,121	5.08
32	Total Secondary	375	17,450	6.54
33	Service Drops - number			
34	Overhead	45,017	280	12.60
35	Underground	24,239	1,021	24.75
36	Total Services	69,256	539	37.35
37	Meters - number			
38	Residential	65,938	60	3.96
39	Commercial	4,059	775	3.15
40	Industrial	3	80,000	0.24
41	Total Meters	70,000	105	7.34
42	Miscellaneous Equipment - number			
43	Switches - number			
44	Overhead	275	15,000	4.13
46	Pad Mount	130	35,000	4.55
47	Subsurface	602	15,000	9.03
48	Total Switches	1,007	17,582	17.71
49	Reclosers - number	30	50,000	1.50
50	Capacitor Banks - number			
51	Overhead	205	16,000	3.28
52	Pad Mount	7	30,000	0.21
53	Total Capacitors	212	16,462	3.49
54	Regulators- number	5	50,000	0.25
55	OH Booster - number	10	6,000	0.06
	Fuses - number			
45	Overhead	991	4,000	3.96
56	Pad Mount	159	25,000	3.98
57	Subsurface	27	35,000	0.95
	Total Fuses	1,177	7,548	8.88
58	Interrupter - number	6	75,000	0.45
59	Jbox - number	359	6,000	2.15
60	Street Lights (estimated)			1.83
61	Total Miscellaneous			36.32
59	TOTAL DISTRIBUTION			397.75
60	TOTAL TRANSMISSION/DISTRIBUTION			439.25

Table 9.4.3.1
Curve Types and Average Service Lives

Line No.	[A] Description	[B] FERC Account	[C] Curve Type	[D] ASL
1	TRANSMISSION			
2	Land and Rights of Way	350		
3	Transmission Lines	356	L4	48
4	Transmission Poles	355	R3	37
5	Transmission Towers	354	S2	65
6	DISTRIBUTION			
7	Land and Rights of Way	360		
8	Substations	362	L0	43
9	Overhead Conductors and Devices			
10	12kv Overhead	365	R1	37
11	Poles - number	364	L0	37
12	Underground Conductors and Devices			
13	12kv Underground	367	S3	31
14	Trenching	366	R3	63
15	Transformers			
16	Overhead	368	R0.5	32
17	Underground			
18	Pad Mount	368	R0.5	32
19	Subsurface	368	R0.5	32
20	Secondary (Low Voltage Circuits)			
21	Overhead	365	R1	37
22	Underground	367	S3	31
23	OH Services	369	R0.5	41
24	UG Services	369	R4	44
25	Meters	370	R2	32
26	Miscellaneous Equipment			
27	Switches			
28	Overhead	365	R1	37
29	Pad Mount	367	S3	31
30	Subsurface	367	S3	31
31	Reclosers	365	R1	37
32	Capacitors			
33	Overhead	365	R1	37
34	Pad Mount	367	S3	31
35	Sub Surface	367	S3	31
36	Regulators	365	R1	37
37	OH Booster	365	R1	37
38	OH Fuses	365	R1	37
39	PM Fuses	367	S3	31
40	SS Fuses	367	S3	31
41	Interrupter	367	S3	31
42	J Box	367	S3	31

Table 9.4.4
Detailed RCN and RCNLD
Original Area Facilities SMUD Proposes to Condemn
As of December 31, 2004

	[A]	[B]	[C]	[D]	[E]
		As of 12/31/2004			
Line No.	Description	Average Age	RCN	Condition Percent	RCNLD
		years	$ million		$ million
1	TRANSMISSION				
2	Land and Rights of Way	14.5	7.50	100.00%	7.50
3	Transmission Lines	15.5	9.23	53.54%	4.94
4	Transmission Poles	31.0	5.26	47.39%	2.49
5	Transmission Towers	9.5	19.51	75.10%	14.65
6	TOTAL TRANSMISSION	14.5	41.50	71.29%	29.59
7	DISTRIBUTION				
8	Land and Rights of Way	14.6	16.10	100.00%	16.10
9	Substations				
10	West Sacramento	29.7	14.42	70.98%	10.23
11	Deepwater	27.2	3.36	72.23%	2.43
12	Davis	25.1	8.83	73.71%	6.51
13	Woodland	28.1	8.98	72.19%	6.49
14	Plainfield	30.1	1.05	70.82%	0.74
15	Total Substations	28.0	36.64	72.04%	26.40
16	Overhead Conductors and Devices				
17	Overhead Feeders	17.7	20.19	75.76%	15.29
18	Poles - number	-	20.25	64.14%	12.99
19	Total Overhead	8.8	40.44	69.94%	28.28
20	Underground Conductors and Devices				
21	Underground Feeders	13.6	96.60	72.66%	70.19
22	Trenching	13.6	88.29	94.39%	83.34
23	Total Underground	13.6	184.89	83.03%	153.52
24	Transformers				
25	Overhead	26.9	8.09	60.65%	4.91
26	Underground				
27	Pad Mount	13.5	13.68	76.86%	10.51
28	Subsurface	20.8	10.36	67.36%	6.98
29	Total Underground	16.6	24.03	72.77%	17.49
30	Total Transformers	19.2	32.13	69.71%	22.40
31	Secondary (Low Voltage Circuits)				
32	Overhead	17.7	1.46	75.93%	1.11
33	Underground	13.6	5.08	73.18%	3.72
34	Total Secondary	14.5	6.54	73.79%	4.82
35	Service Drops				
36	Overhead	17.7	12.60	79.35%	10.00
37	Underground	13.6	24.75	88.26%	21.84
38	Total Services	15.0	37.35	85.25%	31.84
39	Meters				
40	Residential	16.0	3.96	71.70%	2.84
41	Commercial	16.0	3.15	71.70%	2.26
42	Industrial	16.0	0.24	71.70%	0.17
43	Total Meters	16.0	7.34	71.70%	5.26
44	Miscellaneous Equipment				
45	Switches				
46	Overhead	22.6	4.13	69.63%	2.87
47	Pad Mount	7.2	4.55	86.59%	3.94
48	Subsurface	17.1	9.03	63.51%	5.74
49	Total Switches	15.8	17.71	70.87%	12.55
50	Reclosers	12.2	1.50	82.16%	1.23
51	Capacitors				
52	Overhead	15.7	3.28	78.01%	2.56
53	Pad Mount	3.3	0.15	95.06%	0.14
54	Sub Surface	2.5	0.06	96.44%	0.06
55	Total Capacitors	14.9	3.49	79.06%	2.76
56	OH Regulators	13.1	0.25	81.18%	0.20
57	OH Booster	22.1	0.06	70.25%	0.04
58	OH Fuses	18.6	3.96	74.49%	2.95
59	PM Fuses	6.8	3.98	87.90%	3.49
60	SS Fuses	8.6	0.95	83.88%	0.79
61	Total Fuses	12.3	8.88	81.49%	7.24
62	Interrupter	7.8	0.45	85.70%	0.39
63	J Box	8.5	2.15	85.38%	1.84
	Street Lights (estimated)		1.83	50.00%	0.91
64	Total Miscellaneous	14.1	36.32	74.78%	27.16
65	TOTAL DISTRIBUTION	14.6	397.75	79.39%	315.79
66	TOTAL TRANSMISSION/DISTRIBUTION	14.6	439.25	78.63%	345.38

Table 9.5.2
Pacific Gas and Electric Company
Detailed Calculation of RCN and RCNLD
As of December 31, 2004 and January 1, 2008

	[A]	[B]	[C]	[D]	[E]
Line		As of 12/31/2004		As of 1/1/2008	
No.	Description	RCN	RCNLD	RCN	RCNLD
		$ million	$ million	$ million	$ million
1	TRANSMISSION				
2	Land and Rights of Way	7.50	7.50	7.96	7.96
3	Transmission Lines	9.23	4.94	8.91	4.33
4	Transmission Poles	5.26	2.49	4.74	2.06
5	Transmission Towers	19.51	14.65	19.94	14.51
6	TOTAL TRANSMISSION	41.50	29.59	41.55	28.85
7	DISTRIBUTION				
8	Land and Rights of Way	16.10	16.10	17.09	17.09
9	Substations				
10	West Sacramento	14.42	10.23	14.27	9.92
11	Deepwater	3.36	2.43	3.34	2.36
12	Davis	8.83	6.51	8.79	6.34
13	Woodland	8.98	6.49	8.91	6.29
14	Plainfield	1.05	0.74	1.04	0.72
15	Total Substations	36.64	26.40	36.34	25.64
16	Overhead Conductors and Devices				
17	Overhead Feeders	20.19	15.29	20.22	14.81
18	Poles - number	20.25	12.99	19.49	12.17
19	Total Overhead	40.44	28.28	39.71	26.98
20	Underground Conductors and Devices				
21	Underground Feeders	96.60	70.19	99.14	65.14
22	Trenching	88.29	83.34	93.32	86.63
23	Total Underground	184.89	153.52	192.45	151.77
24	Transformers				
25	Overhead	8.09	4.91	7.50	4.46
26	Underground				
27	Pad Mount	13.68	10.51	13.66	9.98
28	Subsurface	10.36	6.98	10.18	6.50
29	Total Underground	24.03	17.49	23.84	16.48
30	Total Transformers	32.13	22.40	31.35	20.94
31	Secondary (Low Voltage Circuits)				
32	Overhead	1.46	1.11	1.48	1.07
33	Underground	5.08	3.72	5.29	3.44
34	Total Secondary	6.54	4.82	6.77	4.52
35	Service Drops				
36	Overhead	12.60	10.00	12.78	9.87
37	Underground	24.75	21.84	26.18	22.09
38	Total Services	37.35	31.84	38.96	31.96
39	Meters				
40	Residential	3.96	2.84	4.02	2.65
41	Commercial	3.15	2.26	3.20	2.11
42	Industrial	0.24	0.17	0.24	0.16
43	Total Meters	7.34	5.26	7.46	4.92
44	Miscellaneous Equipment				
45	Switches				
46	Overhead	4.13	2.87	4.09	2.72
47	Pad Mount	4.55	3.94	4.74	3.86
48	Subsurface	9.03	5.74	8.72	5.14
49	Total Switches	17.71	12.55	17.56	11.72
50	Reclosers	1.50	1.23	1.53	1.20
51	Capacitors				
52	Overhead	3.28	2.56	3.33	2.48
53	Pad Mount	0.15	0.14	0.16	0.14
54	Sub Surface	0.06	0.06	0.06	0.06
55	Total Capacitors	3.49	2.76	3.55	2.68
56	OH Regulators	0.25	0.20	0.25	0.20
57	OH Booster	0.06	0.04	0.06	0.04
58	OH Fuses	3.96	2.95	3.98	2.83
59	PM Fuses	3.98	3.49	4.20	3.43
60	SS Fuses	0.95	0.79	0.99	0.77
61	Total Fuses	8.88	7.24	9.18	7.03
62	Interrupter	0.45	0.39	0.47	0.38
63	J Box	2.15	1.84	2.28	1.79
64	Street Lights (estimated)	1.83	0.91	1.94	0.87
65	Total Miscellaneous	36.32	27.16	36.83	25.91
66	TOTAL DISTRIBUTION	397.75	315.79	406.96	309.71
67	TOTAL TRANSMISSION/DISTRIBUTION	439.25	345.38	448.51	338.57

Table 9.7.2
Pacific Gas and Electric Company
Reduction in Value Due to Net Salvage
As of January 1, 2008

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Description	RCN	Average Age	Composite Trend Factor	Original Cost	Net Salvage %	Net Salvage Amount	Remaining Life	Present Worth Factor	Affect on Value
		$ million	years		$ million		$ million	years	@ 6.25%	$ million
1	TRANSMISSION									
2	Land and Rights of Way	7.96	40.1			0.0%	-			-
3	Transmission Lines	8.91	39.2	5.27	1.69	-31.0%	(0.52)	12.5	0.439	(0.23)
4	Transmission Poles	4.74	33.2	3.56	1.33	-50.0%	(0.67)	10.0	0.481	(0.32)
5	Transmission Towers	19.94	42.1	5.97	3.34	-40.0%	(1.34)	28.1	0.165	(0.22)
6	TOTAL TRANSMISSION	41.55	40.1	6.53	6.36		(2.53)			(0.77)
7	DISTRIBUTION									
8	Land and Rights of Way	17.09	19.4			0.0%	-			
9	Substations	36.34	30.9	2.97	12.25	0.0%	-	28.2		-
10	Overhead Conductors and Devices									
11	12kv Overhead	20.22	19.8	1.80	11.24	-49.0%	(5.51)	23.2	0.240	(1.32)
12	Poles - number	19.49	37.7	4.57	4.26	-35.0%	(1.49)	-	0.234	(0.35)
13	Total Overhead	39.71	28.6	2.56	15.51		(7.00)			(1.67)
14	Underground Conductors and Devices									
15	12kv Underground	99.14	16.2	1.51	65.46	-19.0%	(12.44)	15.5	0.392	(4.87)
16	Trenching	93.32	16.2	1.53	60.87	10.0%	6.09	47.3	0.057	0.35
17	Total Underground	192.45	16.2	1.52	126.34		(6.35)			(4.53)
18	Transformers									
19	Overhead	7.50	27.0	1.69	4.43	10.0%	0.44	16.5	0.349	0.15
20	Pad Mount	13.66	16.3	1.36	10.03	0.0%	-	22.2		-
21	Subsurface	10.18	23.6	1.51	6.74	0.0%	-	18.0		-
22	Total Transformers	31.35	21.2	1.48	21.20		0.44			0.15
23	Secondary (Low Voltage Circuits)									
24	Overhead	1.48	19.8	2.00	0.74	-49.0%	(0.36)	23.1	0.246	(0.09)
25	Underground	5.29	16.2	1.61	3.29	-19.0%	(0.63)	15.2	0.399	(0.25)
26	Total Secondary	6.77	17.0	1.68	4.04		(0.99)			(0.34)
27	Service Drops									
28	Overhead	12.78	19.8	1.78	7.17	-60.0%	(4.30)	28.9	0.174	(0.75)
29	Underground	26.18	16.2	1.32	19.81	-40.0%	(7.92)	28.0	0.184	(1.45)
30	Total Services	38.96	17.4	1.44	26.99		(12.23)			(2.20)
31	Meters	7.46	18.3	1.57	4.76	0.0%	-	16.9		-
32	Miscellaneous Equipment									
33	Switches									
34	Overhead	4.09	25.2	2.23	1.83	-49.0%	(0.90)	20.3	0.258	(0.23)
35	Pad Mount	4.74	9.8	1.33	3.58	-19.0%	(0.68)	21.5	0.272	(0.18)
36	Subsurface	8.72	19.1	1.64	5.32	-19.0%	(1.01)	13.9	0.422	(0.43)
37	Total Switches	17.56	18.0	1.64	10.72		(2.59)			(0.84)
38	Reclosers	1.53	15.1	1.55	0.99	-49.0%	(0.48)	26.4	0.198	(0.10)
39	Capacitors									
40	Overhead	3.33	18.6	1.70	1.96	-49.0%	(0.96)	24.0	0.230	(0.22)
41	Pad Mount	0.16	6.3	1.24	0.13	-19.0%	(0.02)	24.7	0.224	(0.01)
42	Sub Surface	0.06	5.5	1.22	0.05	-19.0%	(0.01)	25.5	0.213	(0.00)
43	Total Capacitors	3.55	17.8	1.66	2.14		(0.99)			(0.23)
44	Regulators	0.25	16.0	1.61	0.16	-49.0%	(0.08)	25.8	0.205	(0.02)
45	OH Booster	0.06	25.0	2.26	0.03	-49.0%	(0.01)	20.2	0.279	(0.00)
46	OH Fuses	3.98	21.4	1.93	2.06	-49.0%	(1.01)	22.5	0.237	(0.24)
47	PM Fuses	4.20	9.8	1.32	3.19	-19.0%	(0.61)	21.3	0.277	(0.17)
48	SS Fuses	0.99	11.5	1.36	0.73	-19.0%	(0.14)	19.7	0.308	(0.04)
49	Total Fuses	9.18	15.0	1.53	5.98		(1.75)			(0.45)
50	Interrupter	0.47	10.7	1.35	0.35	-19.0%	(0.07)	20.5	0.292	(0.02)
51	J Box	2.28	11.5	1.34	1.70	-19.0%	(0.32)	19.5	0.306	(0.10)
52	Street Lights (estimated)	1.94								
53	Total Miscellaneous	36.83	15.7	1.67	22.07		(6.30)			(1.76)
54	TOTAL DISTRIBUTION	406.96	19.4	1.75	233.15		(32.43)			(10.34)
55	TOTAL TRANSMISSION/DISTRIBUTIC	448.51	21.3	1.87	239.51		(34.95)			(11.11)

Table 9.7.3.1
Pacific Gas and Electric Company
Comparison of Fair Market Value
Facilities in Original Area Proposed to be Condemned
PG&E System-wide Net Original Cost

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
		System Wide Net Original Cost			Fair Market Value Oringinal Area Proposed to be Condemned		
Line No.	Description	Original Cost	Depreciation Reserve	Net Original Cost	RCNLD	Additional Value	Fair Maket Value
		$million	$million	$million	$million	$million	$million
1	Net Original Cost/Fair Market Value						
2	Transmission						
3	Rights of Way	186.60		186.60	7.96	4.16	12.12
4	Lines	1,330.27	576.17	754.11	20.89	10.91	31.80
5	Subtotal	1,516.87	576.17	940.70	28.85	15.07	43.92
6	Other	2,196.30	951.26	1,245.04	-	-	-
7	Total Transmission	3,713.17	1,527.42	2,185.75	28.85	15.07	43.92
8	Distribution						
9	Overhead	4,130.09	1,724.26	2,405.83	28.05	14.65	42.70
10	Underground	4,065.30	1,697.21	2,368.09	155.21	81.09	236.30
11	Other - Rights of Way	139.31		139.31	17.09	8.93	26.02
12	Other	5,486.77	2,290.65	3,196.12	109.36	57.13	166.49
13	Total Distribution	13,821.47	5,712.12	8,109.35	309.71	161.81	471.52
14	Total Transmission and Distribution	17,534.64	7,239.54	10,295.10	338.56	176.88	515.44
15	Numbers of Customers						
16	Total			4,990,000			70,000
17	Portion Served Underground			10%			35%
18	Number Served Overhead			4,491,000			45,500
19	Number Served Underground			499,000			24,500
20	Per Customer			$/customer			$/customer
21	Transmission						
22	Rights of Way			37			173
23	Lines			151			454
24	Distribution						
25	Rights of Way			28			372
26	Other			641			2,378
27	Overhead Lines per Overhead Customer			536			939
28	Underground Lines per Underground Customer			4,746			9,645
29	Total Assuming 35% Underground			2,866			7,363
30	Ratio - Original Area Proposed to Be Condemned Divided by Net Original Cost						2.57

Reference: PG&E 2004 FERC Form 1
Note: For Original Area, Overhead and Underground Lines include Feeders and Low-Voltage Circuits

Figure 9.7.4.1
Pacific Gas and Electric Company
Sacramento Area Power Flows
Pre-Condemnation

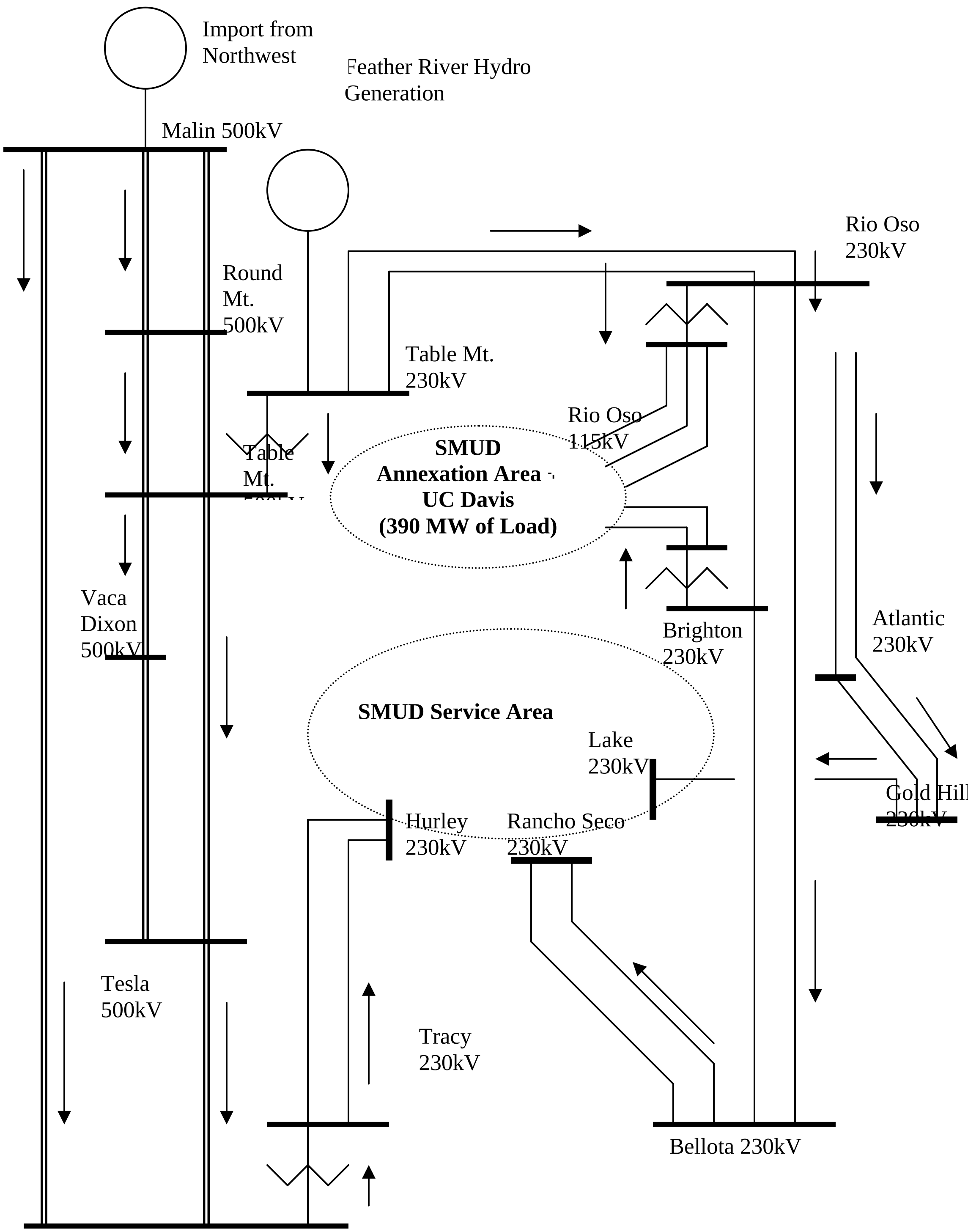


Figure 9.7.4.2
Pacific Gas and Electric Company
Sacramento Area Power Flows
Assuming Condemnation

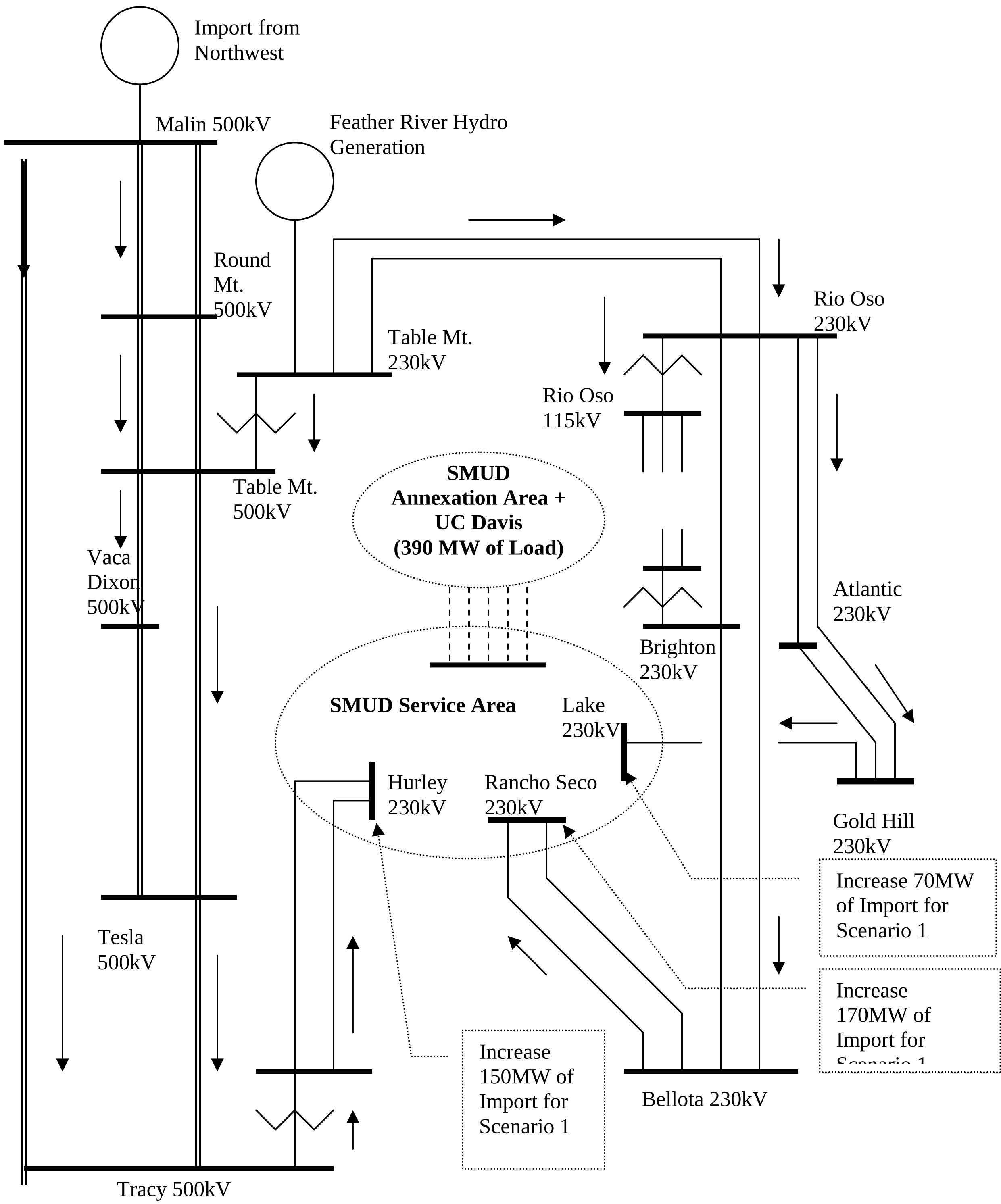


Table 9.8.1.1
Detailed Comparison of Fair Market Value
Beck versus Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
Line		Beck Case 4			B&V			Difference - Beck less B&V			
No.	Description - Units	Quantity	Unit Cost	RCN	Quantity	Unit Cost	RCN	Not Included	Quantity	Unit Cost	RCN
			[D] / [B]	$ million		[G] / [E]	$ million	$ million	$ million	$ million	$ million
1	TRANSMISSION										
2	Land and Rights of Way	-	-	-	-	-	7.50	(7.50)	-	-	(7.50)
3	Transmission Lines- miles	138	396,561	54.67	75.59	449,825	34.00		24.69	(4.03)	20.67
4	TOTAL TRANSMISSION			54.67			41.50	(7.50)	24.69	(4.03)	13.17
5	DISTRIBUTION										
6	Land and Rights of Way	-	-	-	2,300	7,000	16.10	(16.10)	-		(16.10)
7	Substations - MVA										
8	PG&E Owned										
9	West Sacramento	90	70,171	6.32	105	137,310	14.42		(1.05)	(7.05)	(8.10)
10	Deepwater	16	84,441	1.35	16	210,272	3.36		-	(2.01)	(2.01)
11	Davis	120	60,277	7.23	135	65,401	8.83		(0.90)	(0.69)	(1.60)
12	Woodland	135	56,646	7.65	120	74,865	8.98		0.85	(2.19)	(1.34)
13	Plainfield	12	48,831	0.59	10	104,738	1.05		0.10	(0.56)	(0.46)
14	Subtotal PG&E	373	62,018	23.13	386	94,928	36.64	-	(1.01)	(12.50)	(13.51)
15	Customer Owned										
16	Tyco Plastics	11	79,672	0.84	-	-	-	0.84		-	0.84
17	Hunt	11	92,245	0.97	-	-	-	0.97		-	0.97
18	Post Office	11	167,671	1.88	-	-	-	1.88		-	1.88
19	Subtotal Customer	32	114,380	3.68	-	-	-	3.68	-	-	3.68
20	Total Substations	405	66,179	26.82	386	94,928	36.64	3.68	(1.01)	(12.50)	(9.83)
21	Overhead Conductors and Devices - miles										
22	12kv Overhead	443	25,593	11.34	537	37,589	20.19		(3.54)	(5.31)	(8.85)
23	Poles - number	10,999	2,104	23.14	18,286	1,107	20.25		(8.07)	10.96	2.89
24	Total Overhead	443	77,832	34.47	537	75,295	40.44	-	(11.61)	5.65	(5.96)
25	Underground Conductors and Devices - miles										
26	12kv Underground	260	108,030	28.05	354	273,246	96.60		(25.65)	(42.90)	(68.55)
27	Trenching - miles	-	-	-	354	249,750	88.29	(88.29)	-		(88.29)
28	Total Underground - miles	260	108,030	28.05	354	522,996	184.89	(88.29)	(25.65)	(42.90)	(156.84)
29	Transformers - number										
30	Overhead	4,434	1,254	5.56	5,347	1,514	8.09		(1.15)	(1.39)	(2.53)
31	Underground						-			-	
32	Pad Mount	1,489	5,435	8.09	2,104	6,500	13.68		(3.34)	(2.24)	(5.58)
33	Subsurface	966	3,095	2.99	1,387	7,466	10.36		(1.30)	(6.06)	(7.37)
34	Total Underground	2,455	4,514	11.08	3,491	6,884	24.03	-	(4.65)	(8.30)	(12.95)
35	Total Transformers	6,889	2,416	16.64	8,838	3,635	32.13	-	(5.79)	(9.69)	(15.48)
36	Secondary (Low Voltage Circuits) - miles										
37	Overhead	56	25,343	1.41	134	10,877	1.46		(1.99)	1.94	(0.05)
38	Underground	125	129,593	16.20	240	21,121	5.08		(14.96)	26.08	11.12
39	Total Secondary	181	97,435	17.61	375	17,450	6.54	-	(16.94)	28.02	11.07
40	Service Drops - number										
41	Overhead	40,682	324	13.19	45,017	280	12.60		(1.41)	2.00	0.59
42	Underground	-	-	-	24,239	1,021	24.75	(24.75)	-		(24.75)
43	Total Services	40,682	324	13.19	69,256	539	37.35	(24.75)	(1.41)	2.00	(24.16)
44	Meters - number										
45	Residential	36,613	131	4.79	65,938	60	3.96		(3.84)	4.67	0.83
46	Commercial	3,661	290	1.06	4,059	775	3.15		(0.12)	(1.97)	(2.08)
47	Industrial	407	538	0.22	3	80,000	0.24		0.22	(0.24)	(0.02)
48	Total Meters	40,681	149	6.07	70,000	105	7.34	-	(3.74)	2.47	(1.27)
49	Miscellaneous Equipment - number										
50	Risers	673	394	0.27	Included w/ Trenching		-	0.27			0.27
51	Switches - number										
52	Overhead	407	3,475	1.41	275	15,000	4.13		0.46	(3.17)	(2.71)
53	OH Cutouts/fuses	297	1,370	0.41	991	4,000	3.96		(0.95)	(2.61)	(3.56)
54	Pad Mount	114	6,574	0.75	130	35,000	4.55		(0.11)	(3.70)	(3.80)
55	Subsurface	169	6,868	1.16	602	15,000	9.03		(2.97)	(4.90)	(7.87)
56	Total Switches	987	3,780	3.73	1,998	10,845	21.67	-	(3.57)	(14.37)	(17.94)
57	Reclosers	31	9,404	0.29	30	50,000	1.50		0.01	(1.22)	(1.21)
58	Capacitor Banks - number										
59	Overhead	176	6,105	1.07	205	16,000	3.28		(0.18)	(2.03)	(2.21)
60	Pad Mount	13	9,997	0.13	7	30,000	0.21		0.06	(0.14)	(0.08)
61	Total Capacitors	189	6,373	1.20	212	16,462	3.49	-	(0.12)	(2.17)	(2.29)
62	Regulators	8	1,810	0.01	5	50,000	0.25		0.01	(0.24)	(0.24)
63	OH Booster	-	-	-	10	6,000	0.06	(0.06)	-		(0.06)
64	PM Fuses	-	-	-	159	25,000	3.98	(3.98)	-		(3.98)
65	SS Fuses	-	-	-	27	35,000	0.95	(0.95)	-		(0.95)
66	Interrupter	-	-	-	6	75,000	0.45	(0.45)	-		(0.45)
67	Jbox	-	-	-	359	6,000	2.15	(2.15)	-		(2.15)
68	Street Lights			-			1.83	(1.83)	-	-	(1.83)
69	Total Miscellaneous			5.51			36.32	(9.15)	(3.67)	(17.99)	(30.81)
70	TOTAL DISTRIBUTION			148.37			397.75	(134.61)	(69.82)	(44.96)	(249.38)
71	TOTAL TRANSMISSION/DISTRIBUTION			203.04			439.25	(142.11)	(45.12)	(48.99)	(236.22)
72	Davis 1107 Adjustment			(2.11)			-	(2.11)	-	-	(2.11)
73	NET RCN as of 12/31/04			200.93			439.25	(144.22)	(45.12)	(48.99)	(238.33)
74	Composite Condition Percent			50.83%			78.63%				
75	RCNLD as of 12/31/04			102.14			345.38				(243.24)
76	Other Elements of Value Due PG&E										
77	Capital Additions (Section 5)						44.09				(44.09)
78	Change in Value - 12/31/04 - 1/1/08 (Section 5)						(6.82)				6.82
79	Going Concern Value (Section 6)						123.39				(123.39)
80	Other Assets (Section 7)						20.50				(20.50)
81	Liabilities (Section 7)						(11.11)				11.11
82	Total Fair Market Value as of 1/1/08						515.44				(413.30)

Notes
Col [J], Line 26: Based on the difference in units multiplied by B&V's unit cost (260-354)*273,246=-25.65 million
Col [G], Line 59: Davis substation not included in the above B&V detail.

Table 9.8.1.2
Summary Condition Percent
Beck versus Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line		Beck			Black & Veatch		
No.	Description - Units	RCN	RCNLD	Condition %	RCN	RCNLD	Condition %
		$ million	$ million	[C] / [B]	$ million	$ million	[F] / [E]
1	Transmission Plant						
2	Rights of Way	0.00	0.00		7.50	7.50	100.00%
3	Transmission Lines	54.67	11.08	20.26%	34.00	22.09	64.97%
4	Total Transmission Plant	54.67	11.08		41.50	29.59	
5	Distribution Plant						
6	Rights of Way	0.00	0.00		16.10	16.10	100.00%
7	Substations	26.82	21.16	78.92%	36.64	26.40	72.04%
8	Overhead Feeders	34.47	19.24	55.81%	40.44	28.28	69.94%
9	Underground Feeders	28.05	17.40	62.02%	184.89	153.52	83.03%
10	Transformers	16.64	11.37	68.31%	32.13	22.40	69.71%
11	Low Voltage Circuits	17.61	10.67	60.56%	6.54	4.82	73.79%
12	Service Drops and Meters	19.27	9.99	51.83%	44.70	37.11	83.03%
13	Miscellaneous Equipment	5.51	2.42	43.98%	36.32	27.16	74.78%
14	Total Distribution Plant	148.37	92.24		397.75	315.79	
15	Total Transmission/Distribution	203.04	103.32	50.89%	439.25	345.38	78.63%
16	Less: Davis (1107)	(2.11)	(1.18)	55.88%	0.00	0.00	0.00%
17	Total	200.93	102.14	50.83%	439.25	345.38	78.63%

Table 9.8.2.1
Detailed Comparison of Fair Market Value
Staff versus Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
		Staff			B&V			Difference - Staff less B&V			
Line No.	Description - Units	Quantity	Unit Cost [D] / [B]	RCN $ million	Quantity	Unit Cost [G] / [E]	RCN $ million	Not Included $ million	Quantity $ million	Unit Cost $ million	RCN $ million
1	TRANSMISSION										
2	Land and Rights of Way	-	-	7.42	-	-	7.50		-	(0.08)	(0.08)
3	Transmission Lines- miles	78	406,590	31.71	75.59	449,825	34.00		0.98	(3.27)	(2.29)
4	TOTAL TRANSMISSION			39.13			41.50	-	0.98	(3.35)	(2.37)
5	DISTRIBUTION										
6	Land and Rights of Way	159	3,508	0.56	2,300	7,000	16.10		(7.51)	(8.03)	(15.54)
7	Substations - MVA										
8	PG&E Owned										
9	West Sacramento	90	54,289	4.89	105	137,310	14.42		(0.81)	(8.72)	(9.53)
10	Deepwater	16	115,381	1.85	16	210,272	3.36		-	(1.52)	(1.52)
11	Davis	131	42,042	5.49	135	65,401	8.83		(0.19)	(3.15)	(3.34)
12	Woodland	146	30,693	4.47	120	74,865	8.98		0.78	(5.30)	(4.52)
13	Plainfield	12	81,472	0.98	10	104,738	1.05		0.16	(0.23)	(0.07)
14	Subtotal PG&E	394	44,828	17.66	386	94,928	36.64	-	(0.06)	(18.92)	(18.98)
15	Customer Owned										
16	Tyco Plastics	-	-	-	-	-	-		-	-	-
17	Hunt	-	-	-	-	-	-		-	-	-
18	Post Office	11	7,143	0.08	-	-	-	0.08		-	0.08
19	Subtotal Customer	11	7,143	0.08	-		-	0.08	-	-	0.08
20	Total Substations	405	43,786	17.74	386	94,928	36.64	0.08	(0.06)	(18.92)	(18.90)
21	Overhead Conductors and Devices - miles										
22	12kv Overhead	416	76,720	31.95	537	37,589	20.19		(9.25)	21.01	11.76
23	Poles - number	10,560	-	-	18,286	1,107	20.25	(20.25)	-		(20.25)
24	Total Overhead	416	76,720	31.95	537	75,295	40.44	(20.25)	(9.25)	21.01	(8.49)
25	Underground Conductors and Devices - miles										
26	12kv Underground	259	270,888	70.07	354	273,246	96.60		(25.70)	(0.83)	(26.53)
27	Trenching		-	-	354	249,750	88.29	(88.29)	-		(88.29)
28	Total Underground	259	270,888	70.07	354	522,996	184.89	(88.29)	(25.70)	(0.83)	(114.83)
29	Transformers - number										
30	Overhead	3,439	1,682	5.78	5,347	1,514	8.09		(3.21)	0.90	(2.31)
31	Underground						-			-	
32	Pad Mount	1,601	5,277	8.45	2,104	6,500	13.68		(2.65)	(2.57)	(5.23)
33	Subsurface	969	3,211	3.11	1,387	7,466	10.36		(1.34)	(5.90)	(7.24)
34	Total Underground	2,570	4,498	11.56	3,491	6,884	24.03	-	(4.00)	(8.48)	(12.47)
35	Total Transformers	6,009	2,886	17.34	8,838	3,635	32.13	-	(7.21)	(7.58)	(14.78)
36	Secondary (Low Voltage Circuits) - miles										
37	Overhead	55	19,870	1.10	134	10,877	1.46		(1.57)	1.21	(0.36)
38	Underground	125	108,822	13.62	240	21,121	5.08		(12.54)	21.08	8.54
39	Total Secondary	180	81,607	14.72	375	17,450	6.54	-	(14.11)	22.29	8.18
40	Service Drops - number										
41	Overhead	44,595	326	14.55	45,017	280	12.60		(0.14)	2.09	1.95
42	Underground	23,684	1,021	24.18	24,239	1,021	24.75		(0.57)	(0.00)	(0.57)
43	Total Services	68,279	567	38.74	69,256	539	37.35	-	(0.70)	2.09	1.38
44	Meters - number										
45	Residential	66,498	68	4.52	65,938	60	3.96		0.04	0.53	0.57
46	Commercial	3,499	144	0.50	4,059	775	3.15		(0.08)	(2.56)	(2.64)
47	Industrial	3	200	0.00	3	80,000	0.24		-	(0.24)	(0.24)
48	Total Meters	70,000	72	5.03	70,000	105	7.34	-	(0.04)	(2.27)	(2.32)
49	Miscellaneous Equipment										
50	Risers	668	751	0.50	Included w/ Trenching		-	0.50			0.50
51	Switches - number										
52	Overhead	379	3,953	1.50	275	15,000	4.13		0.41	(3.04)	(2.63)
53	OH Cutouts/fuses	322	656	0.21	991	4,000	3.96		(0.44)	(3.31)	(3.75)
54	Pad Mount	273	13,000	3.55	130	35,000	4.55		1.86	(2.86)	(1.00)
55	Subsurface		-	-	602	15,000	9.03	(9.03)	-		(9.03)
56	Total Switches	974	5,399	5.26	1,998	10,845	21.67	(9.03)	1.83	(9.21)	(16.41)
57	Reclosers	29	31,000	0.90	30	50,000	1.50		(0.03)	(0.57)	(0.60)
58	Capacitor Banks - number										
59	Overhead	185	7,450	1.38	205	16,000	3.28		(0.15)	(1.75)	(1.90)
60	Pad Mount		-	-	7	30,000	0.21	(0.21)	-		(0.21)
61	Total Capacitors	185	7,450	1.38	212	16,462	3.49	(0.21)	(0.15)	(1.75)	(2.11)
62	Regulators	8	20,000	0.16	5	50,000	0.25		0.06	(0.15)	(0.09)
63	OH Booster	-	-	-	10	6,000	0.06	(0.06)	-		(0.06)
64	PM Fuses	-	-	-	159	25,000	3.98	(3.98)	-		(3.98)
65	SS Fuses	-	-	-	27	35,000	0.95	(0.95)	-		(0.95)
66	Interrupter	-	-	-	6	75,000	0.45	(0.45)	-		(0.45)
67	Jbox	-	-	-	359	6,000	2.15	(2.15)	-		(2.15)
68	Street Lights			1.83			1.83	-	-	-	-
69	Total Miscellaneous			10.02			36.32	(16.32)	1.71	(11.69)	(26.30)
70	TOTAL DISTRIBUTION			206.16			397.75	(124.79)	(62.87)	(3.93)	(191.59)
71	TOTAL RCN			245.30			439.25	(124.79)	(61.89)	(7.28)	(193.96)
72	Composite Condition Percent			53.14%			78.63%				
73	RCNLD as of 12/31/04			130.34			345.38				(215.04)
74	Other Elements of Value Due PG&E										
75	Capital Additions (Section 5)						44.09				(44.09)
76	Change in Value - 12/31/2004 - 1/1/2008 (Section 5)						(6.82)				6.82
77	Going Concern Value (Section 6)						123.39				(123.39)
78	Other Assets (Section 7)						20.50				(20.50)
79	Liabilities (Section 7)						(11.11)				11.11
80	Total Fair Market Value as of 1/1/08						515.44				(385.10)

Table 9.8.2.2
Summary Condition Percent
Staff versus Black & Veatch

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line		Staff			Black & Veatch		
No.	Description - Units	RCN	RCNLD	Condition %	RCN	RCNLD	Condition %
		$ million	$ million	[C] / [B]	$ million	$ million	[F] / [E]
1	Transmission Plant						
2	Rights of Way	7.42	0.00		7.50	7.50	100.00%
3	Transmission Lines	31.71	14.68	46.28%	34.00	22.09	64.97%
4	Total Transmission Plant	39.13	14.68		41.50	29.59	
5	Distribution Plant						
6	Rights of Way	0.56	0.56	100.00%	16.10	16.10	100.00%
7	Substations	17.74	14.03	79.10%	36.64	26.40	72.04%
8	Overhead Feeders	31.95	13.55	42.42%	40.44	28.28	69.94%
9	Underground Feeders	70.07	43.45	62.02%	184.89	153.52	83.03%
10	Transformers	17.34	11.86	68.40%	32.13	22.40	69.71%
11	Low Voltage Circuits	14.72	8.93	60.66%	6.54	4.82	73.79%
12	Service Drops and Meters	43.76	19.06	43.55%	44.70	37.11	83.03%
13	Miscellaneous Equipment	10.02	4.22	42.08%	36.32	27.16	74.78%
14	Total Distribution Plant	206.16	115.67		397.75	315.79	
15	Total Transmission/Distribution	245.30	130.34	53.14%	439.25	345.38	78.63%

Table 9.8.5.1
Inventory of Selected Map Areas
Beck versus Actual

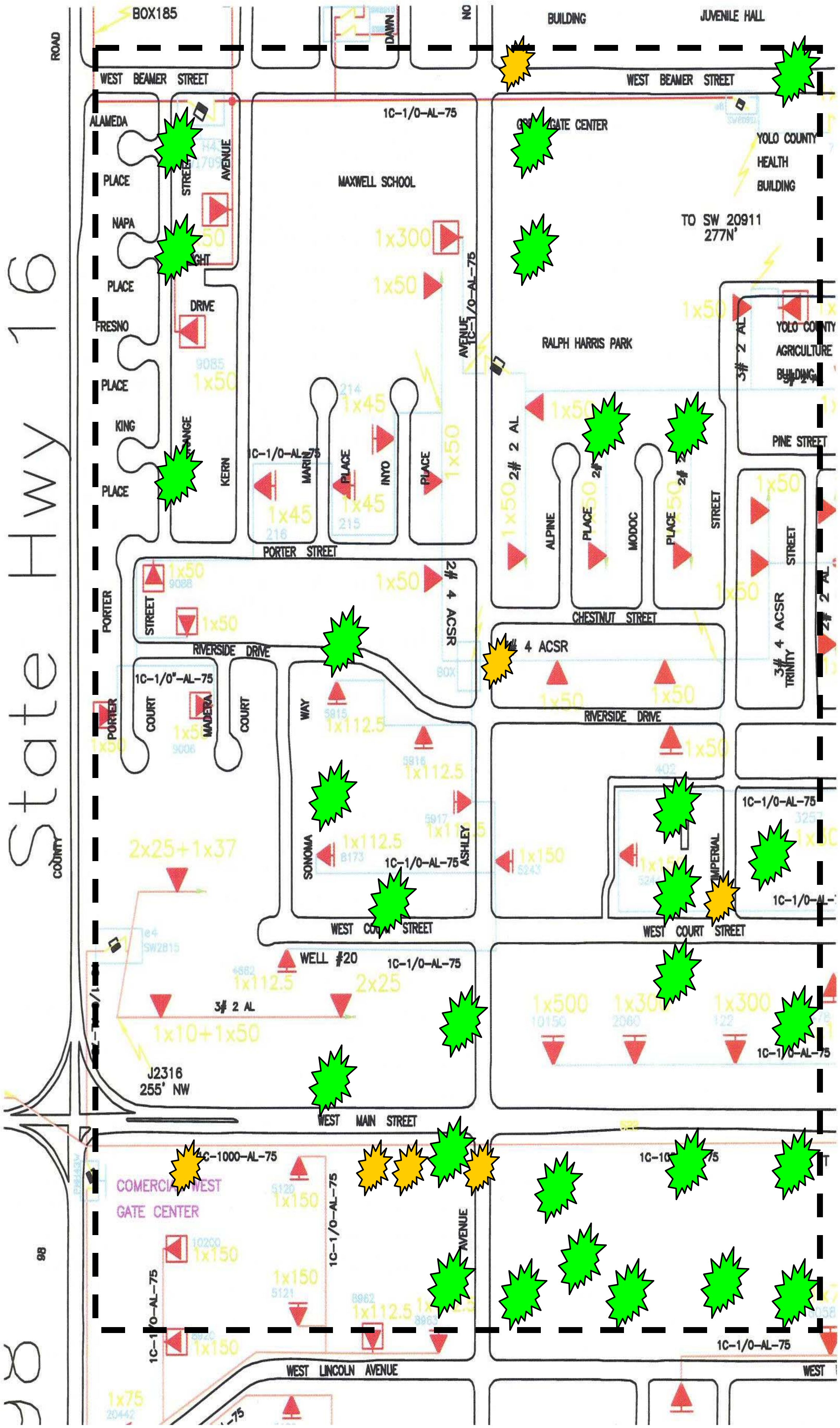
	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Map Location	Description	Beck	Actual	Missed	Percent Missed
						%
1	J-17-6	Transformers	41	69	28	40.58%
2		Switches	4	11	7	63.64%
3		KVA	4,245.0	7,318.0	3,073.0	41.99%
4	M-18-13	Transformers	17	21	4	19.05%
5		Switches	-	2	2	100.00%
6		KVA	1,215.0	2,112.5	897.5	42.49%
7	M-19-14	Transformers	9	13	4	30.77%
8		Switches				
9		KVA	692.5	975.0	282.5	28.97%
10	L-23-24	Transformers	9	15	6	40.00%
11		Switches				
12		KVA	1,700.0	1,797.5	97.5	5.42%
13	J-17-14	Transformers	78	88	10	11.36%
14		Switches				
15		KVA	2,745.0	3,405.0	660.0	19.38%

Figures 9.8.5.1 through 9.8.5.5

Location of Equipment

Located and Missed by Beck

Are Contained on the Following Pages



Map J-17- 6 Summary

28 out of 69 Transformers not identified

7 out of 11 switches not identified

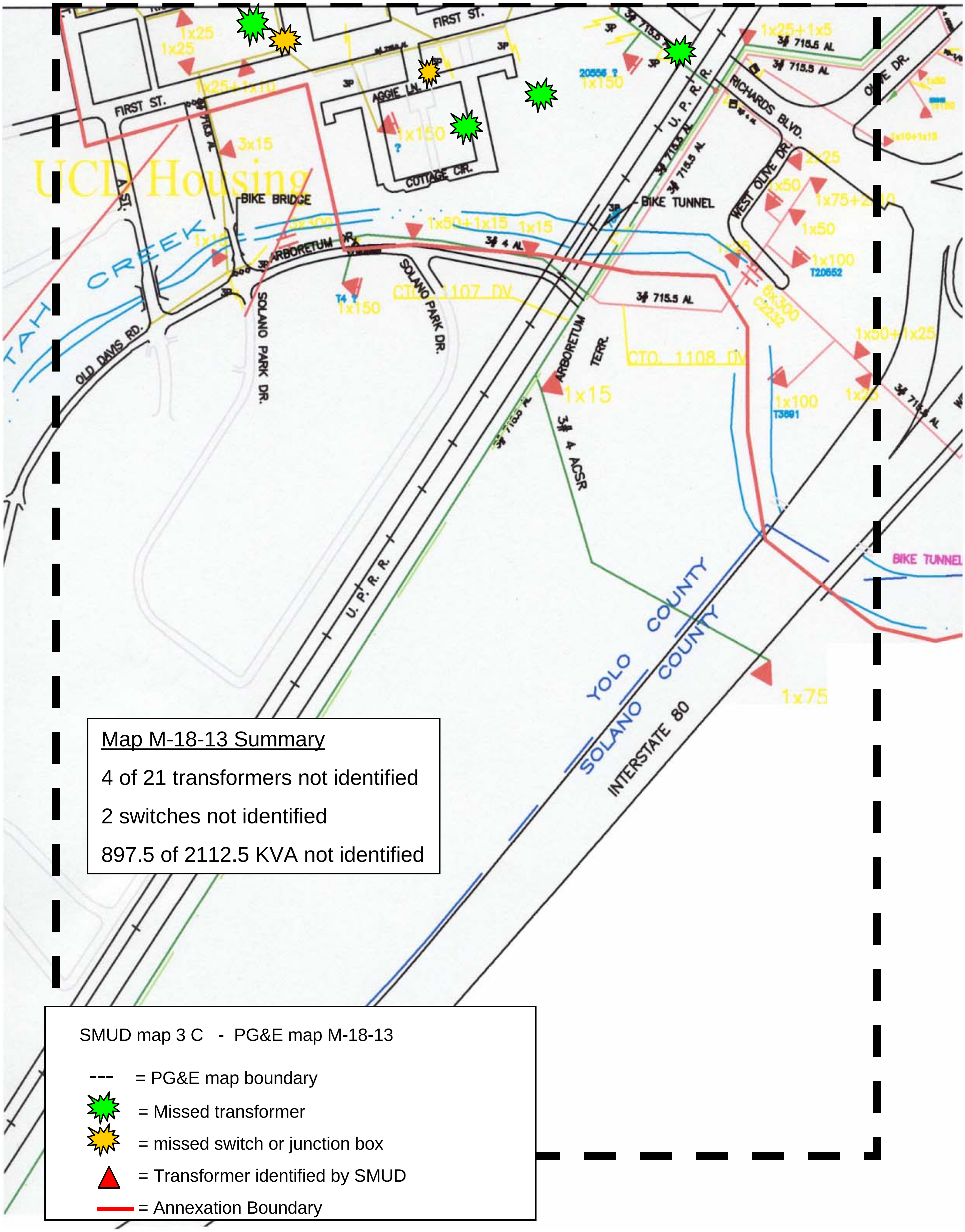
3073 out of 7318 KVA not identified

= PG&E map boundary

= Missed transformer

= Missed switches or J boxes

= SMUD identified trans.



Map M-18-13 Summary

4 of 21 transformers not identified

2 switches not identified

897.5 of 2112.5 KVA not identified

SMUD map 3 C - PG&E map M-18-13

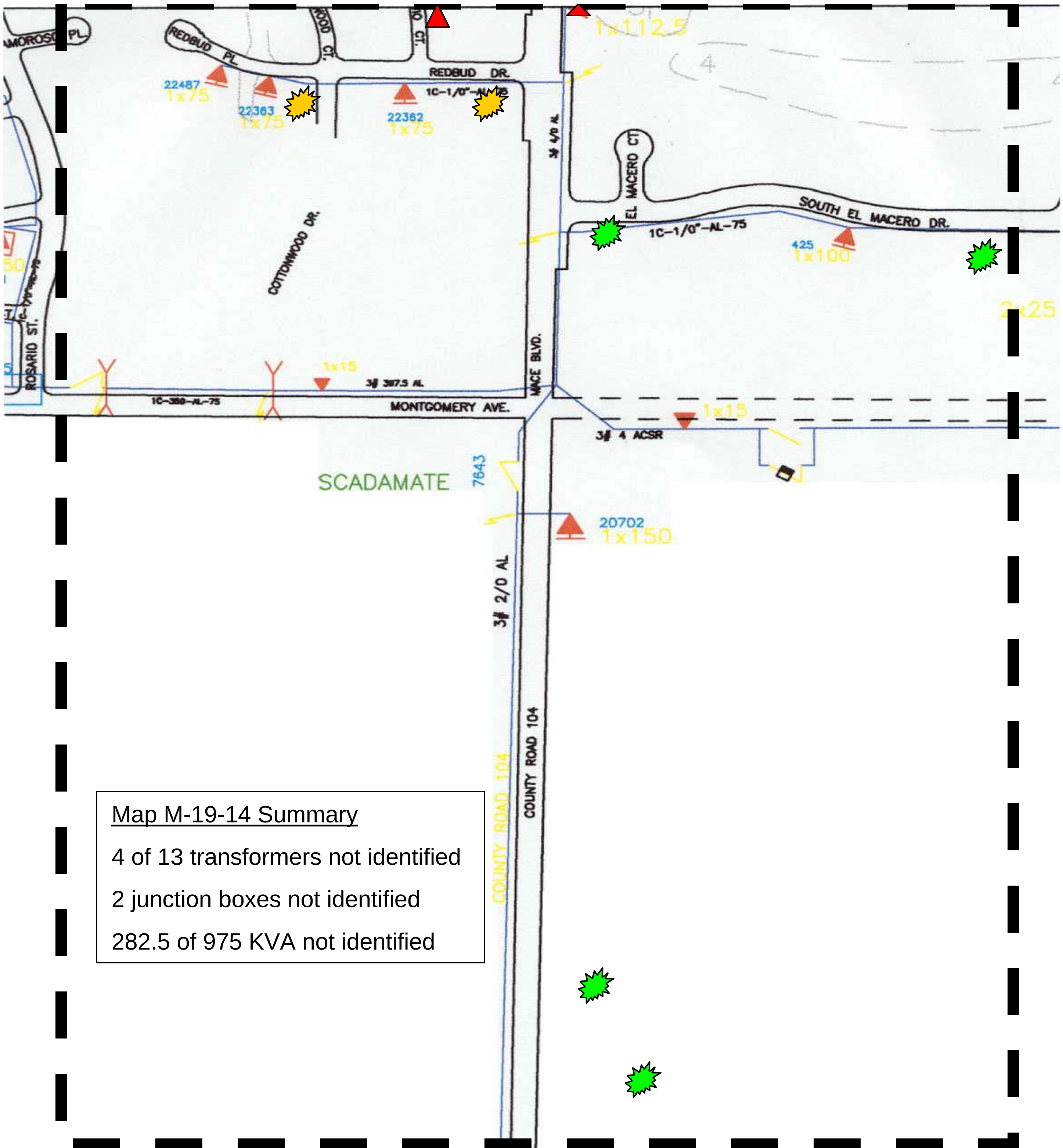
--- = PG&E map boundary

= Missed transformer

= missed switch or junction box

= Transformer identified by SMUD

= Annexation Boundary



Map M-19-14 Summary

4 of 13 transformers not identified

2 junction boxes not identified

282.5 of 975 KVA not identified

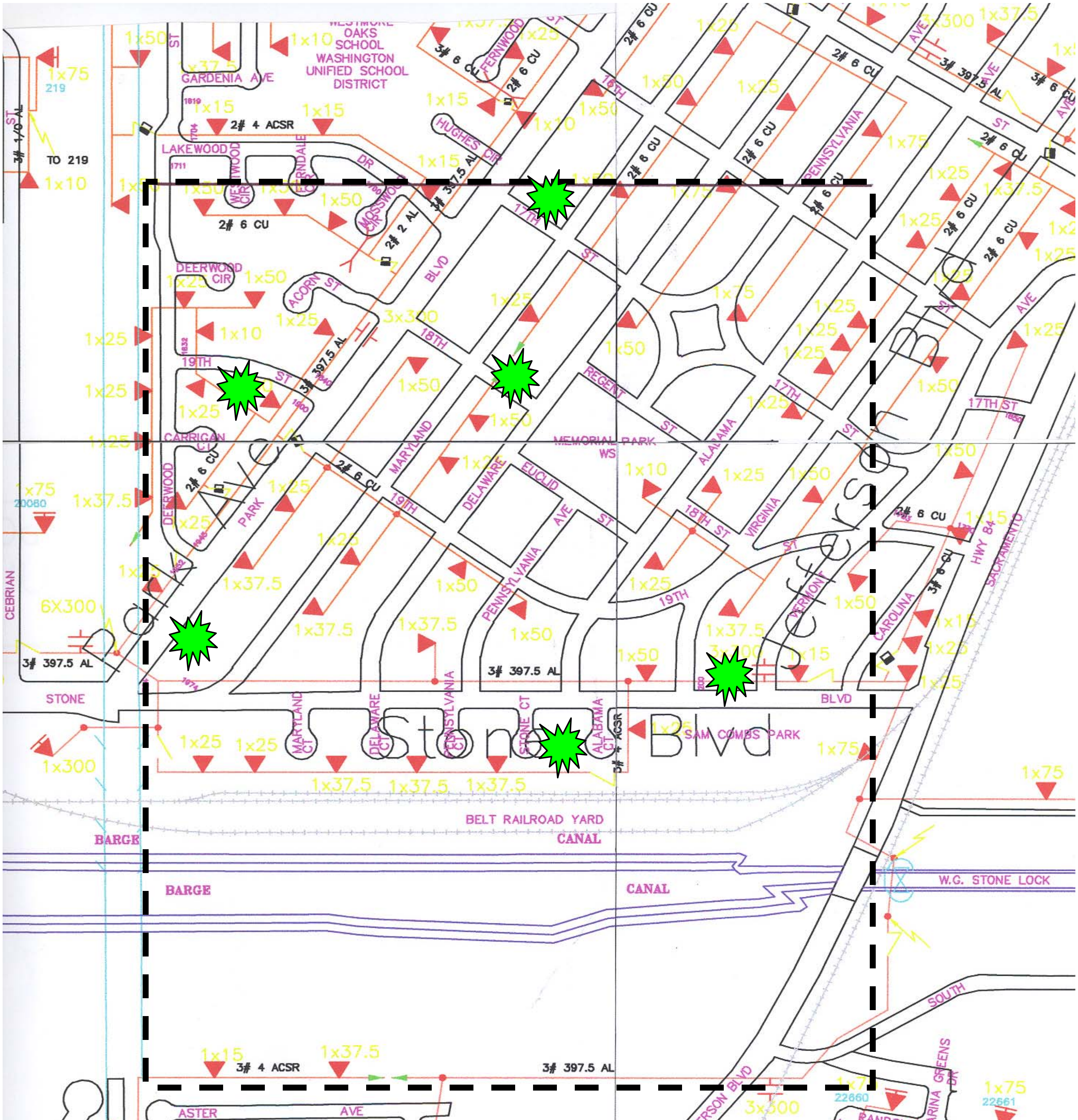
SMUD map 4 C - PG&E map M-19-14

--- = PG&E map boundary

= Transformer not identified by SMUD

= equipment or junction box not identified by SMUD

= Transformer identified by SMUD



Map L-23-24 Summary

6 out of 51 transformers missed

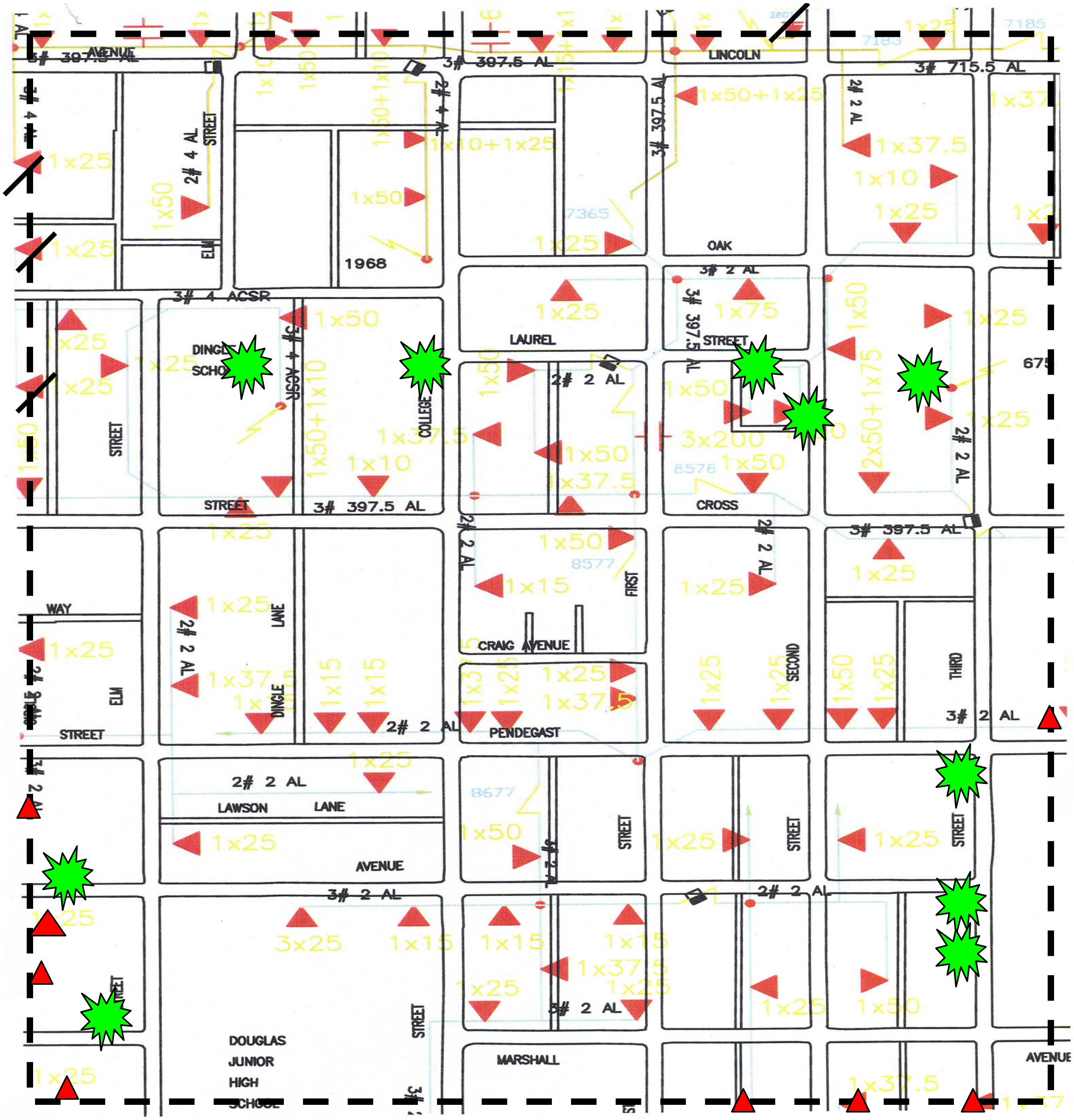
97.5 out of 1797.5 KVA not identified

SMUD Map 7D, 7E, 8D, 8E – PG&E Map L-23-24

- - - = PG&E map boundary

= Missed Transformer

= Transformer identified by SMUD



SMUD Map 2 I – PG&E Map J-17-14

= PG&E map boundary

= Missed Transformer

= Transformer identified by SMUD

= Transformer on next map

Map J-17-14 Summary

10 out of 88 transformers missed

660 out of 3405 KVA missed