Critical Thinking on California IOU Energy Efficiency Performance Incentives from a Consumer Advocate's Perspective

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ABSTRACT

As Integrated Resource Planning (IRP) is experiencing a regulatory renaissance, recast as resource procurement or portfolio management, investor-owned utilities (IOU) are in large part being given regulatory authority to administer multi-million to billion dollar annual ratepayer-funded energy efficiency (EE) portfolios. While all parties recognize there is an inherent financial conflict of interest between selling and saving energy, parties differ on the extent to which regulatory mechanisms can align IOU and customer interests.

Based on their decades of experience with IRP, IOU-administered EE, and regulatory EE performance incentives both in California and on the national level, the authors discuss how the various financial and non-financial incentives for utilities to promote increased sales cannot be wholly eliminated, and even if significantly reduced, that reduction comes at a very high price.

The authors explain why they believe the most fundamental way to motivate IOUs to procure "least cost best fit" (LCBF)[1] energy efficiency is to stop making supply-side investments so attractive by more closely aligning the utilities' authorized returns with the cost of equity capital observed outside the regulatory arena.

If EE performance incentives are adopted for IOUs, the authors describe how to design incentives strategically. Such incentives could promote a diverse energy services market through robust competition in program design and implementation and efficiency savings that also have significant peak demand impacts.

IOUs Have Significant Business and Regulatory Incentives to Promote Higher Electricity Use

Utility Business Model

The utility consumer advocacy movement that began in the late seventies and continues today is in large part focused on reducing the industry's capital requirements by moderating the need for and cost of electric plant and equipment through energy efficiency. Even so, the utility industry maintains a high propensity for capital due to ongoing load growth and replacement and refurbishment of existing generation, transmission, and distribution (GTD) infrastructure. Even with aggressive energy efficiency (and other distributed resources), the nature of the business is,

[1]The authors define "Least-cost best fit (LCBF) as the procurement of cost-effective supply- and demand-side resources that regardless of ownership, meet capacity and energy deliverability requirements. Energy efficiency resources are constructed from a "bottoms up" approach that aggregates the demand and energy savings from various energy-saving measures and activities into applicable end-use categories such as space cooling, space heating, lighting, and refrigeration, in order to provide near- and long-term peaking, intermediate, and baseload requirements."

and will in large part remain, the production and delivery of electricity by means of capital-intensive facilities.

Command over capital as a means of corporate survival and growth is not just desirable, but an utter necessity for electric utilities. To attract capital, investor-owned utilities must have an overarching corporate objective to increase shareholder value (SV) by increasing stock prices (SP) and dividends (given that utilities typically pay out more dividends than most other businesses) (DV)) Raising SP and DV in turn means maximizing earnings or net income (NI) and increasing the growth in earnings per share (ES). In turn, NI = Revenues minus expenses (Ex), with revenues based on the price (P) of electricity and the level of kilowatt hour sales (S).

Overview of Utility Rate Setting

The electricity price includes:

- Expenses (EX) including the cost of operation including fuel and O&M (variable costs), depreciation expense associated with existing plant (which becomes part of the utility's cash flow); payroll and property taxes; and income taxes.[2]
- An allowed Rate of return (ROR) on utility's invested capital or "rate base" (RB). RB largely consists of the undepreciated portion of the original and legitimate cost of plant and equipment.[3] The ROR includes debt interest, preferred stock dividends, and a return on equity (ROE). When rates are set, NI is presumed equal to the ROE allowance, but it can diverge from this point between rate cases.

Examining these components more closely, under conventional regulation, <u>between rate cases</u>, an increase in kilowatt hour sales is likely to translate into higher amounts of NI, as the variable cost of sales is often less than the revenue received.[4] This phenomenon is particularly true for the preponderance of utilities that have fuel adjustment charges that automatically true up rates for changes in fuel and purchased power costs. In a utility rate case itself, NI is generally increased by increasing either RB or ROE.[5]

An increase in earnings or net income (NI), allows growth in earnings per share (ES) if stock does not need to be sold in large quantities to finance new construction because earnings

[2] Income taxes include both taxes currently paid to the government and future "deferred taxes" arising from accelerated depreciation of utility plant for tax purposes. These deferred taxes become part of the utility's cash flow in the short term. If the utility system is growing, the balance of deferred taxes increases. However, if the system stops growing, deferred taxes could end up being repaid to the government, reducing the utility's cash flow. Moreover, income taxes are set to allow the utility to earn its ROE <u>after taxes</u>. A utility is thus unlike many industries, because its taxes are assumed to be paid before the ROE is set.

[3] With reasonable allowances for interest during construction and for working capital and a reduction for deferred taxes collected through the income tax allowance from ratepayers before they are paid to the government.

[4] Between rate cases, a decrease in expenses or rate base relative to the amount on which rates were set can also translates into higher levels of NI.

[5] California, unlike most states, has a regulatory feature that is very favorable to utilities – a future test year. For example, the current PG&E rate case is setting rates for 2007. A "future test year" means that California rates are set based on a hypothetical future year, using a forecast of EX and RB (rather than historical figures adjusted for known and measurable changes). In this relatively unique California context, another way to increase NI is for the utility to overforecast future expenses and RB.

can be retained.[6] Increasing earnings per share (which in turn supports increasing dividends (DV) plus the retention of earnings) improves the stock price (SP) and allows a utility with a growing rate base to finance significant amounts of that growth internally.[7] Thus, shareholder value (SV) for the regulated utility operation is thus largely a function of rate base, rate of return, and kilowatt hour sales.[8]

Recent Trends in the Cost of Equity Capital and the Utility Propensity to Build

There is one more critical factor affecting SV, and that is the level of the ROE relative to the utility's cost of capital. If the ROE is higher, then the utility's SV will be higher than if ROE is lower, all else being equal.

Regulators are supposed to set the authorized ROE at a level equal to the cost of equity capital. While the cost of equity capital is not directly measurable, there are many indications, both quantitative and anecdotal, suggesting that the cost of equity in the economy, (particularly for an investment such as a utility company that is generally of lower risk than the market as a whole), is lower than currently authorized utility ROE levels.

If the ROE is higher than the cost of capital, the result is that the IOUs obtain even more benefits from increasing RB through new steel-in-the-ground investments, particularly when the IOUs' stock is selling above book value.[9]

Consider the recent prices of California utility stocks:[10]

- PG&E -- book value $21.02, stock price $37.12. (77% above book)
- Edison International -- book value $20.30, stock price $43.61 (114% above book)

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[6]While earnings per share increase more in the event that construction can be financed entirely through retained earnings, if a utility's stock sells above book value it can still increase its book value and earnings per share (though by a somewhat lesser amount) by selling new shares on the open market to finance the rest of its construction budget.

[7] In the short run, earnings increase only by cutting costs (either through productivity improvements or service degradation) or raising sales (absent a revenue-sales decoupling mechanism). Cost-cutting can either be legitimate or a result of over-forecasting EX or RB in a state with a future test year.

[8] This is not the only way to increase shareholder value. As we know from the diversification of utilities, sometimes, shareholder value can be enhanced by successful investments in other lines of business. Also, within the regulated utility model, shareholder value can be enhanced by successful asset management and energy trading. The role of affiliates in shareholder value is raised later.

SV - Shareholder Value; DV – Dividends; SP - Stock Price; NI - Net Income (or Earnings); ES - Earnings Per Share; R – Revenues; Ex – Expenses; P – Price; S = Sales RB - Rate Base; RoR - Rate of Return

- SV *f* (DV and SP)
- (DV and SP) *f* (NI and ES)
- (NI and ES) *f* (R – Ex)
- R = (P * S)
- R = (Ex + RB X RoR)

Thus, SV *f* (RB X RoR) and SV *f* (S)

[9] This phenomenon (that a regulated utility will preferentially choose capital-intensive technologies) is known as the Averch-Johnson effect after a seminal paper written in the 1960s. (Averch and Johnson, 1962) Averch-Johnson does not hold under all conditions, but when the utility's stock is selling comfortably above book value and there are indications that the cost of capital is below the utility's return, making choices to increase rate base will increase utility long-run earnings per share and will encourage utilities to choose capital-intensive technologies over technologies with similar long-run costs.

[10] Figures are December 31, 2005 stock prices and end-of-year 2005 book values.

- Sempra -- book value $23.97 stock price $44.84 (87% above book)

California utilities are not unusual in this regard. Utility stocks nationwide are well above book value with a few exceptions of firms harmed by energy trading or the hangover from past energy crises.

Prices dramatically in excess of book value are often a sign that the utility industry is earning returns in excess of the cost of capital. Such conditions are likely to exist today. California's authorized equity returns are 11.35% for PG&E, 11.60% for Edison and 10.70% for SDG&E. (California Public Utilities Commission, 2005)

Both quantitative and anecdotal evidence offered in Appendix A suggests that utility rates of return should be moved to the single-digit range.

Some analysts believe and several state Commissions have found that new generation is more risky than other utility investments such as transmission and distribution wires and needs a higher return.[11] A modest increment of risk could be found reasonable given the longer construction time for generation projects (in states that do not include Construction Work in Progress in the rate base) and the greater risk of regulatory disallowance for generation projects than for distribution projects. However, both of these risks are less for gas-fired generation than large coal and nuclear projects.[12] Different commissions have addressed the issue differently, but the generation risk, when recognized, has generally been modest (less than 100 basis points).[13] Moreover, the argument that utilities need a higher rate of return to compensate for generation risk contradicts the argument that they need similar incentives to undertake allegedly less risky efficiency projects. To give a utility an EE incentive commensurate with supply projects must recognize that the utility is neither investing the capital nor taking the allegedly higher supply risk. If a utility claims that it needs a higher equity return to compensate for the higher risk and higher cost of equity capital in generation, all else being equal, logic would dictate that the utility should also need *less* incentive to engage in less risky efficiency projects.

The reduction of authorized returns to single-digit levels should not be viewed as revolutionary, even though it is necessary not only to protect consumers but to reduce incentives for IOUs to eschew EE and pursue supply resources. Canadian regulators have authorized single-digit equity returns for a number of years. In fact, the first equity return **below 9%** in recent memory has resulted from the current ROE indexing method in Alberta (one of the most economically conservative jurisdictions in North America), which yielded an 8.93% return for energy utilities in 2006. (Atco, Ltd., 2006) In the U.S., the Arkansas PSC authorized returns of 9.4% to 9.7% for three gas utilities in three 2005 rate cases, overriding utility claims that such

[11] The excess "risk" of generation is not a critical issue in California, even if utilities elsewhere have raised it. In the utility investor presentations referenced below, in Appendix A and footnotes 15-16, neither PG&E or Southern California Edison have informed their investors that their new utility-owned generation projects are more risky than transmission or distribution investments.

[12] The nuclear industry is concerned about high required returns because of its capital intensity. A nuclear energy proponent writes: "nuclear power competitiveness will be hampered by a high rate of interest, a required high rate of return on equity, or a high risk premium related to financers' risk aversion." (Lauvergeon, 2001, page 5).

[13] For example, the Iowa Utilities Board rejected a competitive equity return for regulated generation but used the top end of a risk premium analysis (100 basis points above the midpoint) to set a 12.23% return. However, Iowa does not use a fuel adjustment clause (so that generation r\risks are also likely to be higher than in most jurisdictions). (Iowa Utilities Board, 2002) On the other hand, the New Hampshire PSC found that an appropriate regulated return for a block of hydro and fossil assets was only 21 basis points above the average for an integrated utility and set the generation equity return at only 9.63%. (New Hampshire Public Service Commission, 2005)

low returns were unprecedented on a nationwide basis and would therefore reduce the utilities' ability to attract capital, while the New Hampshire PSC authorized a 9.63% return for fossil and hydro generation in June 2005.

The Relationship between Sales, Peak Loads and Construction

The ability to make capital investments is promoted when usage (particularly usage during peak periods) is growing. Most wires investments are driven by peak load growth in local areas (either increasing use per customer or increases caused by the addition of new customers). Generation investments are also often justified by the need to meet loads during unhedged peak periods. Recovery of capital investments requires IOU revenues that are at minimum stable and at best increasing over time. This is achieved by IOUs' cultivating electricity sales through the following occurrences: the addition of new customers; overall growth in use per customer; and retention and growth of sales during strategic high-cost periods.

The stock analysts are clear that rate base is the key. "Mark Sadeghian, a utilities analyst with the Morningstar research firm, said PG&E appears to be on stable footing, with its future growth tied to getting more customers or winning higher rates. 'I see no red flags,' said Sadeghian, who does not own PG&E stock. 'It's the same story that it will be -- that in order to get the stock going, it depends on strong growth in the rate base.'" (Baker, 2005)

A California example of this phenomenon can be found in the policy testimony of Alan Fohrer, Treasurer of SCE, in the SCE 2006 General Rate Case (GRC). Mr. Fohrer discusses the very large ($6.6 B) capital investment plan in transmission and distribution (T&D) for 2004-08. He attributes $1.1 billion or 17% to "customer growth," and $1.8 billion or 28% to "load growth for…existing substations and circuits to meet peak load." (Fohrer, 2004, p. 12) Mr. Fohrer offers the following historical perspective on the state's electric rate levels:

> In addition, California's moderate climate, strong building codes, and utility EE programs have constrained electricity consumption to a point where per-capita electricity consumption is one of the lowest in the nation. In conjunction with increasing penetration of air conditioning use, these factors have caused customer loads to be relatively low on average but also very 'needle peaked.' As a result, SCE's system 'load factor' has declined steadily for decades and is one of the lowest in the nation. Consequently, the high fixed costs invested for power supply and delivery infrastructure must be collected through fewer kWh sales, thereby creating high rates when measured on a per-kWh basis. (Fohrer, 2004, p. 8)

Additional examples are included in the footnotes.[14]

[14] PG&E and its financial analysts point to "connections of new customers and demand growth" as one key driver for increases in distribution rate base. Significant transmission growth is also expected. PG&E projects 7.5% earnings growth based on a 6.3% growth in rate base from 2006-2010 (even *excluding* about 800 MW of utility-owned generation announced in April, 2006). (PG&E Corporation, 2006).
Financial analysts' response to a 28% drop in second quarter 2005 profits at PG&E Corporation reported is also instructive. "Morningstar equity analyst Mark Sadeghian said PG&E's growth will come from the acquisition of new physical assets like transmission lines, distribution equipment and generating plants, whose cost will be covered by utility ratepayers if state regulators approve. 'PG&E has a pretty ambitious plan to get back to basics and build the rate base.'" (Tansey, 2005)

Furthermore, California utilities own unregulated entities involved in the generation of electricity (except for PG&E which lost its affiliates during the bankruptcy and is building almost 1400 MW of new generation through a regulated platform (Pacific Gas and Electric Company, 2006). While affiliate transactions for long-term generation contracts were previously banned, the recent Palomar decision now permits utility affiliates to reap development fees from generation projects sold on a turnkey basis to the parent utility. (California Public Utilities Commission, 2004a) The overall ban on contracting has been repealed, replaced with an "Independent Evaluator" structure to be used if a utility proposes either to build a project or sign a long-term contract with an affiliate. (California Public Utilities Commission, 2004b) This change in regulatory policy leaves the utilities in even more of a position to profit from load growth through either regulated generation or unregulated affiliates.

This throws a huge wrench into any stakeholder aspirations that rate of return regulation can be sufficiently counter-balanced through alternative mechanisms such as performance based ratemaking (PBR). The cows are already out of the barn. Not only utilities but also their unregulated affiliates thrive on growing shareholder value. Indeed, one key purpose of such generation subsidiaries is to allow regulated utilities a means to exit their own regulated generation markets (given higher cost embedded power plants), compete as IPPs at the wholesale level through affiliates, and pursue lucrative opportunities in regional transmission.[15]

Sales Decoupling Mechanisms do not Make IOUs Completely Indifferent to Sales Volume Relative to Recovering Capital Investments

Revenue true-up mechanisms such as the former Electric Revenue Adjustment Mechanism (ERAM) (and the new proliferation of California balancing accounts that accomplish the same thing) do not change the underlying basis of the IOUs' business model. ERAM addresses the short run (between rate case) requirement that revenues from electricity sales be sufficient to recover, but not exceed, the regulatory allowed cost of current capital investments.[16]

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[15] This corporate strategy has worked for Edison International, as reflected in the following material quoted from Morgan Stanley, 2004. "We have increased our price target for Overweight-rated Edison International shares to $28 from $24, as our new analysis of the Edison Mission Energy (EME) merchant subsidiary shows $6 – 10 per share of long-term intrinsic value….Edison's Mountainview generating project has already added nearly $2 per share in net present value, by our estimate, and we believe further generation and transmission buildouts could add upside. Edison is building Mountainview as an unregulated subsidiary, to protect the long-term value of its sizable investment and avoid potentially harsh future regulation. The SoCal Ed utility will purchase Mountainview's output under a 30-year contract. The contract details are not public, but the company suggested that the return will exceed a regulated utility return. The plant should contribute to EPS [earnings per share] in 2006.")(emphasis added).

As an additional example, John Bryson, CEO of Edison International, (Bryson, 2005) offers a look at the new unregulated future – a "balanced business mix" of "strong utility operating in a large and *rapidly growing* service territory" and "unregulated business platform with large base of low-cost coal assets".[15] Edison International growth is projected to be strong due to:

- The hybrid system of electricity regulation in the U.S., EIX benefits from having both a utility and a competitive generator;
- Substantial growth in the Southern California Edison utility rate base anticipated through the remainder of the decade; and
- Opportunities in the unregulated businesses.

[16] This discussion below does not consider Performance-Based Ratemaking (PBR), which can be implemented independently of decoupling. It relates to a regulatory structure where decoupling is tied either to conventional ratemaking or to annual attrition revenue increases (annual inflation and rate base adjustments with no significant

A stable or increasing sales base is paramount to the IOUs' corporate business model because it is the critical driver for recurring capital-intensive investments in a combination of replacement and/or expansion of aging infrastructure, and the addition of new generation, transmission and distribution facilities, which are largely driven by peak load increases. The cost of new "steel in the ground" projects are included in periodic rate case filings where increases in allowed revenues are accompanied by upward adjustments to historic sales data. ERAM does not dissolve the underlying truth that sales growth - be it kilowatt hours or widgets - is what makes the world go 'round for the capitalist business model.

In fact, by reducing the utility's overall business risk, ERAM (or a similar revenue-per-customer decoupling mechanism) reduces the utility's cost of capital. If the utility's rate of return is not reduced to reflect the lower risk (commensurate with the reduction in the cost of capital), ERAM may have far different short-term and long-term impacts. Giving a utility decoupling protection without reducing the return on equity to reflect the reduced risk would skew utility shareholder incentives toward growth in capital investments by not recognizing the risk reduction. Thus, where the rate of return is above the cost of capital to begin with, it ends up even farther above the cost of capital adjusted for the reduced risk than if decoupling did not exist.

Thus, ERAM alone may actually provide long-term incentives to reduce EE program effectiveness (particularly in peak demand periods) to promote capital spending. The type of programs prevalent in California (which focus heavily on energy savings relative to peak savings) may in fact be the logical result of a combination of: (1) regulatory support for energy efficiency that causes utility administrators to want to deliver "results;" (2) ERAM protection; (3) generous rate of return awards in excess of the cost of capital that do not reflect the risk reduction created by ERAM and encourage rate base growth supported by growth in peak demand; and (4) utility program administration.

A stable to declining rate of growth in electric sales over time leads to a leveling out or lessening in the magnitude of required capital investments, which in turn erodes shareholder value particularly when the utility rate of return exceeds the cost of capital or the investments that are deferred are viewed as having relatively low risk. As an addition to ERAM, various forms of performance incentives for regulatory-induced energy efficiency are an attempt to compensate investors for this perceived loss in earnings opportunity.

Cost Allocation Methodology and Other Regulatory Incentives Also Can Influence IOUs' Design of Energy Efficiency Programs

There are two additional financial incentives related to the regulatory process that motivate the utility to increase sales. First, the ability to raise rates in any rate case from a political standpoint depends on the sales forecast. A cost request that would result in a $200 million increase if sales were flat could become a $100 million increase if sales were growing (because of a higher estimate of revenue at present rates). This improves the "optics" of rate increases for the utility in the press and public opinion, and may cause regulators to be less cost conscious than when rates are rising more rapidly in at least some cases.

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productivity offset) as are now the norm in California. The recent expectation of increasing utility distribution costs ended California's ten-year experience with PBR, which was put in place during a period of declining utility costs.

Second, retention of sales during strategic high-cost periods is a significant factor in the IOUs' corporate objective because peak load is a critical driver of the sizing or scale of most GTD facilities and is widely used for cost allocation to customer classes. For instance, if residential efficiency savings are greater in lighting which is largely off peak than peak load air conditioning; the residential class load factor will continue to deteriorate relative to the system average and to other customer classes. Residential customers can thus remain the IOUs' "cash cow" through various carefully crafted peak-based cost allocation methodologies, while increases are not spread as heavily to large non-residential customers. As a result, programs that threaten the existing cost allocation structure (such as air conditioner efficiency to reduce peak demand) may not be fully pursued.

Performance Incentives for Energy Efficiency are Expensive and have not Proven Successful

Achieving IOU indifference to EE compared with supply-side resources requires at minimum that the combination of ERAM and performance incentives make EE as profitable as the IOUs' most expensive capital-intensive resource plan. In order to induce IOUs to embrace EE over other capital-intensive resources, regulators must make EE more profitable than alternative resources. EE incentives must be substantial in light of utility incentives to promote sales growth to encourage revenue increases (even while keeping rates down) to create a heavy peak cost allocation for the residential class, and to increase peak demand to build rate base. In other words, giving utilities EE incentives that are comparable to its alternatives will be far more expensive than changing administrators and choosing an organization without conflicting corporate goals. Unfortunately, no regulatory mechanisms can eliminate the reality that IOU energy efficiency administration creates tremendous opportunities for IOUs to game the system because the underlying business model of increasing sales to support ongoing capital investments remains intact. <u>IOU EE administration will not influence the underlying corporate business model; rather, the business model will influence IOU administration</u>. (A corollary is that the utility business model would not be expected to influence an independent EE administrator in the same way.)

Given that IOUs still face dueling incentives because their long-term position is enhanced by sales growth, the outcome of ERAM plus performance incentives is poor, particularly with today's high authorized returns. Performance incentives for IOUs either end up being extremely expensive or do not provide enough money to overcome long-standing corporate incentives for growth, thus becoming ineffective and costly windfalls for shareholders. If performance incentives were large enough to be competitive with current supply side incentives, EE delivered by utilities would be far more costly than EE delivered by other entities, if not more costly than supply side resources. It would be cheaper to change the EE program administrator than to give the utility incentives to offset the current incentives for supply resources.

Most if not all of the revenue true-up mechanisms and performance incentives that are on the table today are familiar artifacts from the first wave of regulatory-induced resource planning. A plethora of regulatory carrots and sticks have been tried with minimal to negative results. For instance, history reflects that, despite receiving incentives, California utilities slashed energy efficiency programs in mid 1990s. The end result was that they created a large portion of the 2000-2001 energy crisis by not achieving 1800 MW of savings that they promised in the early 1990s as a rationale to stop the construction of new generation. (Marcus, 2003)

Making EE Performance Incentives as Strategic as Possible

Incentives for EE cannot neutralize the incentive to build. Only a lower ROE can begin do that. Nevertheless, a more strategic view of incentives could foster a thriving and diverse energy services market through robust competition in program design and implementation. How?

First, recognize that incenting IOUs for simply administering EE portfolios will not necessarily foster the best mix of portfolios and programs. Rewarding administration will beget more administration. The reward for performing EE portfolio administration should be the ability to retain and continue the function. Thus, the administrative assignment should be revisited from time to time. This is more in keeping with regulatory treatment of IOU administration of equivalent supply side functions.

Second, focus on rewarding programs that deliver verified and sustained savings in a LCBF manner, with the BF or "Best Fit" aspect very important. In other words, energy efficiency efforts should focus on the critical end uses that drive supply-side procurement. Examples of these are: Residential and commercial space cooling load, which are the drivers California's summer system peak; with peak demand growing more rapidly than energy consumption. Residential and commercial space cooling load is driving California's $200 to $450 per MWh peak period avoided costs (calculated from E-3 Corporation, 2004) and providing the backbone for some of the 30+ proposed coal-fired facilities in the intermountain west.

Third, understand that a system of incentives correlated directly to the quantitative achievement of regulatory prescribed MW and MWh energy targets -- without consideration of supply side procurement critical loads -- will encourage efforts to 'meet the goals' with less than solid savings.

Fourth, recognize that an incentive system with rewards based on maximizing net benefits (higher benefit/cost ratios) and penalties based on kilowatt hours not achieved will encourage the IOUs to "dig broad" but <u>not</u> "dig deep." Rather, it will give IOUs incentives to:

- continue to go after the cheap and easy savings such as lighting (the highest B/C ratio);
- give lower priority to "lost opportunities" that must be achieved at specific times or lost for decades even if they are less cost-effective than the cheapest programs with more discretion in timing;
- develop programs that look better on paper than savings delivered in the field (e.g., refrigerator programs not geared by size that indirectly encourage customers to use their rebates to buy bigger refrigerators, thus offsetting some of the efficiency gains)
- construct portfolios based on energy savings that are not necessarily correlated to the critical end uses that drive supply-side procurement.[17]

Rewards based on net benefits have the additional highly undesirable effect of allowing utility shareholders to profit from high fuel prices. With the same incentive structure, higher gas

[17] California's peak demand is growing more rapidly at 2.4 percent annual than the annual growth rate in energy consumption at 2% (2000 data). Across the state, the relationship between annual energy use and peak demand (load factor) is deteriorating. Residential and commercial space cooling accounts for about one-third of the daily summer system peak. Residential air conditioning load is characteristically very low load factor/peak coincident; meaning it is concentrated on a seasonal and time period basis to hot summer days. An incentive mechanism based on maximizing net benefits and annual energy savings does not encourage utilities to save more difficult and costly space cooling load; most particularly residential. (Mitchell, 2005).

prices would raise shareholder incentives at the expense of ratepayers even if the utility expended no additional effort on EE.

Fifth and finally, recognize that reward/penalty systems based solely on kilowatt hours without correlation to the critical end uses that drive supply-side procurement could work to erode system load factor over time. This can exacerbate supply-side procurement because statewide and IOU-specific capacity infrastructure requirements (G, T & D) can remain largely unchanged in relation even to significant reductions in annual energy requirements.[18] Thus, if incentives are to be used, the reward/penalty system should incorporate into the energy targets the critical end uses that drive supply-side procurement costs.

Conclusion

The most fundamental way to motivate utilities to procure energy efficiency (EE) resources is to stop making supply-side investments so attractive. Incentives must be as strategic as possible in order to promote a diverse energy services market through robust competition in program design and implementation. Revenue true-up mechanisms such as the ERAM may be reasonable for other policy reasons but do not change the underlying basis of the IOUs business model, which to increase rate base. If the risk reducing features of ERAM are not considered by regulators through a lower ROE, ERAM may actually provide long term incentives to reduce EE program effectiveness (in peak periods) to promote capital spending.

Regulators must make EE more profitable than alternative resources in order to motivate the IOUs to embrace EE over other capital-intensive resources. To do that, the first key step must be to reduce the profit incentive on traditional supply-side resources. Otherwise we will just be throwing money at EE when it would be cheaper to have an independent administrator without the supply-side motivation to promote growth. Then, one must develop strategic incentives to foster a thriving and diverse energy services market through robust competition in program design and implementation. The reward for performing EE portfolio administration should be the ability to retain and continue the function since this is more consistent with supply side functions. Regulators should focus on rewarding programs that deliver verified and sustained savings. The regulatory incentive system should include critical end uses and energy savings targets that drive supply-side procurement costs. Such incentives would specifically encourage efficiency programs to reduce residential and commercial space cooling load, which are the drivers of California's summer system peak. This will reduce the inherent financial conflict of interest between selling and saving energy and better align IOU and customer interests.

Appendix A: Additional Information Supporting Lower Equity Returns

Using traditional cost-of-capital metrics, the Columbia Group prepared a quantitative presentation as early as mid-2003 suggesting that utility equity returns should be well under 10%. (Woolridge, 2003)

[18] Without a strong and concerted effort to improve the efficiency of electric space cooling load, peak and super-peak period energy sales will remain relatively unchanged. This means that the current phenomena of peak demand growing more rapidly (2.4%) than energy consumption (2%) in California, will not only continue, but widen if the IOUs energy efficiency programs are successful in saving large quantities of baseload and offpeak energy.

Additional quantitative information comes from the utilities in their role as investors. Utilities have an investment role in two key areas – as managers of pension funds (and similar funds for post-retirement benefits and long-term disability programs) and as managers of nuclear decommissioning funds (which must be invested externally in stocks and bonds).

In the pension fund area, at the same time that it was authorized a return on equity of 11.35%, PG&E claimed that it needed to increase its pension fund contributions by $273 million (subsequently settled at $176 million) in 2007-2009 because it projected that the stock market in the real world was performing far less well than its authorized return. PG&E's own estimate was 8.3%, which it supported by conducting a survey of 10 actuarial firms. The highest of the ten firms expected stock market performance in the next 5-10 years to be 8.3%, and the mean expected performance was 7.5%. (Pacific Gas and Electric Company, 2006b) Southern California Edison and Sempra also expect pension fund returns generally consistent with stock market returns in the 8.5% range. Research has also been conducted across a broader cross-section of companies (including a selection of "comparable" gas companies as well as several other utilities in a recent rate of return case), suggesting expected returns for the stock market as a whole of 10-11% in 2004. (Marcus, 2005)

As managers of decommissioning funds, PG&E and Edison both projected stock market returns for the market as a whole in the vicinity of 8.5% in late 2005.[19]

In addition to examining utility behavior as investors, we can look at analysts' forecasts. Utility rate of return witnesses often rely on "sell side" analysis by entities such as Value Line that tend to project relatively high returns. However, many other analysts forecast relatively low rates of return. Figures from SDG&E's decommissioning case workpapers show the that five investment analysts project returns for U.S. large cap stocks between 7 and 9% and a fifth is considerably lower than 7%.

Another very important piece of quantitative data is a survey of Global CFOs conducted quarterly by Duke University. The most recent survey finds that the expected return on the S&P 500 in excess of 10-year US Treasury bonds (the "equity risk premium") is 2.39% above the return on the 10-year Treasury bond. This is a decline from approximately 4% in 2000, and from slightly below 3% in the third and fourth quarters of 2005. (Graham and Harvey, 2005) With a 10-year treasury trading slightly above 5% today, this risk premium translates into a return on the S&P 500 of around 7.5% based on the most recent figures and 8% based on the earlier 2005 figures.

Anecdotally three recent articles suggest returns for the market as a whole in the same range of 8% or less. One of the articles specifically details Warren Buffett's views of market conditions (Bloomberg, 2003); a second presents the views of five stock market experts on future returns for retirement accounts (*Fortune*, 2005); and the third suggests a ten-year expected return of 6% because of high current price-earnings ratios, with longer term returns closer to 8% (Wibel, 2005). Utility stocks with their rate case structure that guarantees an opportunity to earn a specific return are generally less risky than the average of the market.[20] Therefore, one should expect that they would earn less than a diversified basket of stocks, not more.

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[19] Edison and SDG&E used a Global Insight forecast averaging 8.45% (arithmetic average over the next 20 years for the S&P 500, while PG&E used a Russell & Co., forecast of 8.5%.

[20] After their bouts with poor finances, PG&E and Edison have a "beta" (measure of risk relative to the market as a whole) of approximately 1.0 (in other words, their risk is about equal to the market as a whole), but comparison groups of pure play gas and electric companies tend to have "betas" that are considerably lower, in the range of 0.7

Finally, over the past 50 years a basket of gas utility stocks actually out-performed the S&P 500, suggesting that regulators are not providing appropriate reductions in ROE to reflect the lower long-term risk of these companies. (Marcus, 2005)

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