IMPACTS ASSESSMENT OF PLUG-IN HYBRID VEHICLES ON ELECTRIC UTILITIES AND REGIONAL U.S. POWER GRIDS: PART 2: ECONOMIC ASSESSMENT

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ABSTRACT

The current U.S. electric grid has spare generation and transmission capacity at night. Without considering some of the practical constraints that could apply to the significantly increased operation of the existing capacity or the need to maintain operating reserves, the current spare capacity could generate and deliver the necessary energy to power the majority of the U.S. light-duty vehicle fleet, if that fleet consisted of plug-in hybrid electric vehicles (PHEVs). If this occurred,, it would reduce greenhouse gas emissions, improve the economics of the electricity industry, and reduce the U.S. dependency on foreign oil. Two companion papers investigate this concept. The overall screening approach frames the analysis from a simple grid capability and economics point of view. The first paper (Part 1) discusses the maximum technical potential of PHEVs without adding new electricity infrastructure or considering operational constraints. This second paper (Part 2) provides an economic assessment of the impacts of PHEV adoption on vehicle owners and on electric utilities. To estimate vehicle owner impacts, the paper calculates the life-cycle cost (LCC) of private vehicle transportation for vehicle owners with PHEVs and compares it with the LCC for conventional light-duty vehicles. To calculate the impacts on electric utilities, the paper provides estimates of the impacts of PHEVs on the revenue and cost streams of two sample utilities, one with its own generating resources, and one that is highly dependent on imported power ("wires only"). This calculation assumes that the host utility and the grid will have to make only minor accommodations to absorb a substantial number of vehicles. With these and other assumptions, the paper finds favorable impacts on the LCC of vehicle owners and average costs of power for both types of utilities.

INTRODUCTION

The current U.S. electric infrastructure operates with generation reserves and spare transmission capability the majority of the time. The system operates at its full capacity only a few hundred hours per year at most. Combined with technical improvements in vehicle electronics and batteries, this "spare" capacity has attracted the interest of a number of vehicle and utility researchers. The economics of all-electric vehicles are rapidly changing due to the recent development of commercial hybrid electric vehicles (HEVs) and a fledging after-market for modifications of these vehicles for plug-in capability. Current demand for and commercial production of hybrid and electric vehicles now justifies updated

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analyses of how they can be supported by the bulk power system and the associated consequences. The results obtained in Part 1 of this analysis [Kintner-Meyer et al. 2007] indicate that the use of off-peak power generation and transmission capability could deliver a substantial portion of the energy needed to fuel the nation's light-duty vehicle (LDV) fleet—cars, pickup trucks, sport utility vehicles (SUVs), and vans. Some researchers recently have even explored the idea of using plug-in hybrid electric vehicles (PHEVs) to provide peak electrical power back to the grid using a concept known as vehicle-to-grid (V2G) (see for example, Kempton and Tomić [2005a, 2005b] and Denholm and Short [2006], who also discuss some of the earlier research and some of the utility impacts of PHEV charging, which we deal with at a more detailed level in this paper). However, whether utility-generated electricity is ever used to power a significant portion of the LDV fleet depends on the collective but independent economic decisions of prospective vehicle owners, who need to know whether the purchasing and operating costs of PHEVs are favorable compared with other alternatives, of electric utility executives, who will want to understand the impacts of large-scale LDV electricity consumption on the utility's bottom line, and of utility regulators concerned about the impact on utility rates and consumer power bills. This paper provides some perspective on these questions by comparing the life-cycle costs of PHEVs with three other types of vehicles and by estimating the economic impact on the average costs of power for two dissimilar electric utilities in the existing U.S. power system.

The analysis in this paper is based on a prototype PHEV, an HEV with additional battery-storage capacity sized to satisfy daily average driving requirements (33 miles per day), solely on electricity.[b] The battery is charged with electricity from the electric grid during off-peak hours, all of which occurs during the night. Driving beyond the daily driving range (i.e., long distances) requires that the PHEV's gasoline engine be used. The analysis of this paper focuses on 1) the life-cycle cost (LCC) of a PHEV purchase decision for a variety of electricity prices, gasoline prices, and alternative conventional vehicle efficiencies and 2) the impacts to the cost of electricity as response to a large-scale market penetration of PHEVs that does not require new investment in generation and transmission and distribution (T&D) capacity expansions. We do not discuss the economics of V2G applications. Because we only consider the electrical performance of a PHEV in this paper, the fundamental approach used applies for a pure electric vehicle with electric performance similar to that of a PHEV.

VEHICLE PURCHASER LIFE CYCLE COST (LCC) ANALYSIS

The LCC analysis provides some insights into the economics of PHEV cars from a vehicle purchaser's point of view. We estimate the premium that a prospective vehicle purchaser could pay for a PHEV and still break even on discounted costs when both the premium and the value of energy cost savings are calculated over the life of the vehicle. The LCC economics are considered potentially favorable for a PHEV purchase in those circumstances where a positive premium is calculated. Because the vehicle market is rapidly changing, we make no attempt to compare estimated premiums with actual premiums that may exist currently. The analysis is performed for prospective vehicle purchasers in the states of California and Ohio, the former to reflect an area with high electricity prices, and the latter to reflect more "average" conditions. These states include the service areas of San Diego Gas and Electric and the

(b) It is likely that many drivers of PHEVs will operate their vehicles in a hybrid mode, consuming both gasoline and electricity. For purposes of the simplified screening study, we assume that the PHEV would operate in an electric-only mode. To the extent that drivers operate in a hybrid mode, they and their serving electric utilities will not obtain the cost savings discussed in this paper. Operation in the hybrid mode (e.g., for long commutes, for convenience, or for intercity travel) is beyond the scope of this paper.

Cincinnati Gas and Electric, which are the example electric utilities used in the utility economics analysis in the next section.

Methods

We compare the premium for the purchase of a PHEV car over the price for a conventional car with the savings accrued by using electricity rather than gasoline. The price premium in purchasing a PHEV is amortized over the average length of ownership of 9 years [Hu, 2006]. The following assumptions for the life-cycle cost analysis are used:

- Prevailing discount rate: 8% real
- Life time of ownership: 9 years (ignoring resale value)
- Purchase price premium of PHEV: varying from $1,000 to $10,000
- Price of gasoline: varying from $2.5 per gallon to $3.50 per gallon.
- Average residential electricity rates: California: $0.12 per kWh, Ohio: $0.083 per kWh(c)

To illustrate the sensitivity of the cost-analysis results with respect to the purchasing price premium, gasoline cost, and electricity cost, we choose a range of these three parameters. The residential electric rates are based on average rates determined by state published by the Energy Information Administration [EIA, 2005].

The base-case comparison is performed using a Honda Civic, a compact car with an estimated mixed city-highway fuel economy of 35 miles per gallon (mpg) as the base-case competing vehicle [DOT 2005]. The energy requirements for the PHEV in an electric mode are 0.26 kWh per mile for a compact car. For a broader array of drivers who might be considering an upgrade to a more fuel-efficient vehicle, we also compared the PHEV with a vehicle achieving the current corporate average fuel economy (CAFE) for cars of 27.5 mpg [DOT 2005]. Finally, we compare the PHEV with a Toyota Prius HEV with an estimated mixed city-highway fuel economy of 56 mpg [DOT 2005]. We assume that the PHEV battery has a round-trip full charge and discharge cycle of 80% and an efficiency of 87% for the charger [Duvall 2002, 2003, and 2004]. Discounted maintenance and repair costs are assumed to be the same for conventional vehicles and PHEVs over the life of the vehicle.(d) We also assume that there is no premium or discounted resale value of a PHEV in comparison with conventional vehicles, which allows us to ignore the time period after the 9-year ownership period.

(c) Residential rates in California are tiered, and rates in the top tier are in the range of $0.30 to $0.40 per kWh. However, California does have rate schedules for electric vehicles (EV) and the application of the EV rate schedules requires customers to have a separate meter.

(d) Hybrid battery replacement is an item of repair cost not applicable to internal combustion vehicles. Reducing the cost and extending the lifetime of these batteries is a goal of active current research sponsored by the U.S. Department of Energy and private organizations.

Results

Figure 1 shows the life-cycle-cost analysis results for purchasing and operating a PHEV compared with a conventional high-fuel-efficiency vehicle such as a Honda Civic. The results are expressed by diagonal break-even lines for varying gasoline prices. Each break-even line in the figure assumes a specific gasoline price and delineates a region below and to the left of the line in which a PHEV would have a lower life-cycle cost than a conventional vehicle and therefore would justify a premium purchase price. This is described as a cost-effective region. Above each line is the region where the PHEV is not cost effective. The premium can be read off the horizontal axis for a given electricity price. For instance, using California average residential rates of 12 cents per kWh and a price of the gasoline of $2.50 per gallon, the break-even point for the purchasing premium is $2,000 for California. In the state of Ohio, with lower electric rates, the break-even point at the gasoline price of $2.50 per gallon is $3,000 (see Figure 1).

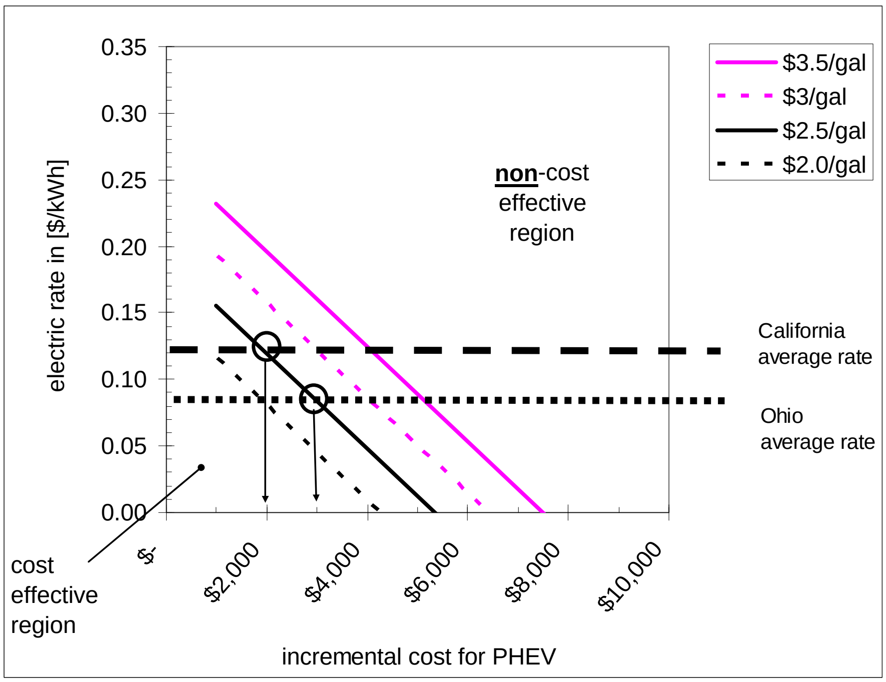

Figure 1: Results of the Life-Cycle Cost Analysis for a PHEV Compared with a Honda Civic with 35 MPG Mixed City-Highway Fuel Economy. Diagonal Lines Denote the Break-Even Point.

Figure 2 offers a comparison to a vehicle meeting the CAFE standard of 27.5 mpg. At California electricity prices of $0.12 per kWh and $2.50 per gallon, the calculated premium rises to about $3,500 over that of a conventional vehicle. In Ohio, the premium rises to slightly below $4,600 (see Figure 2).

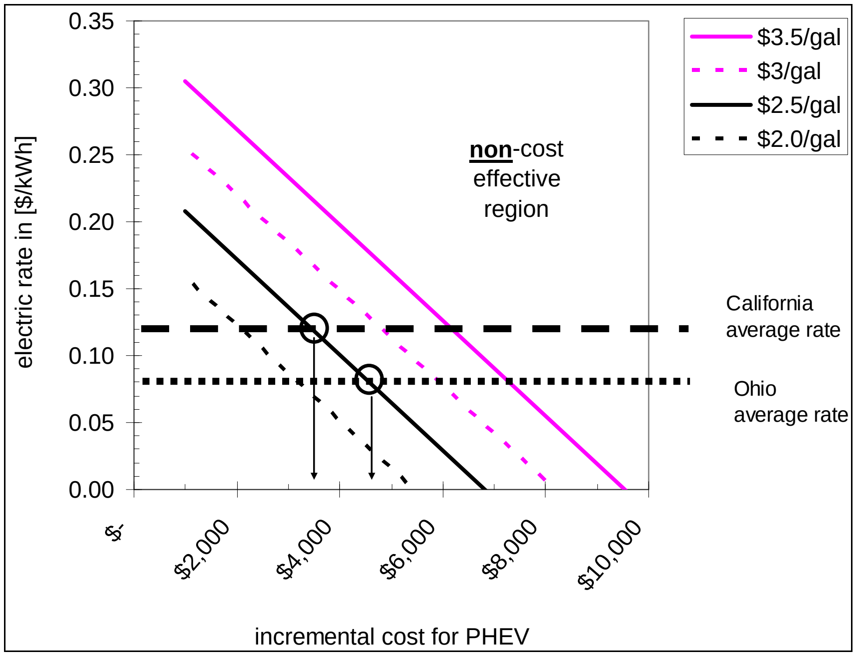

Figure 2: Results of the Life-Cycle Cost Analysis for a PHEV Compared with a Conventional Vehicle with 27.5 MPG Fuel Economy. Diagonal Lines Denote the Break-Even Point.

Examining the cost-effectiveness of a PHEV compact car to an HEV represented by a Toyota Prius with a mixed city/highway fuel efficiency of 56 mpg, we find that with California average residential electricity rates, the allowable purchasing premium is zero. With the lower electric rates in Ohio, the allowable premium for cost-effectiveness is about $1,000, given a fuel cost of $2.50 per gallon (see Figure 3).

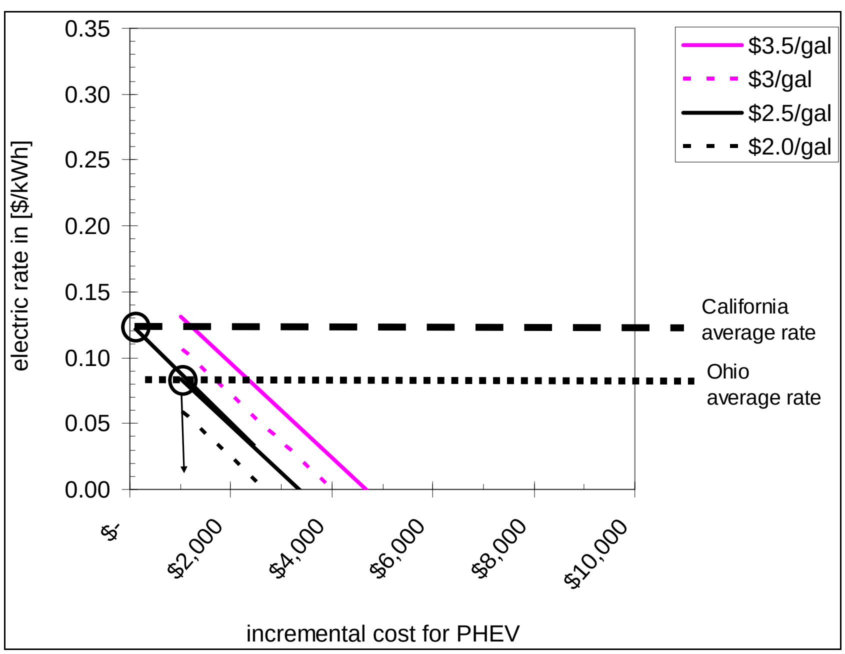

Figure 3: Results of The Life-Cycle Cost Analysis for a PHEV Compared with a Toyota Prius with 56 MPG Mixed City-Highway Fuel Economy. Diagonal Lines Denote the Break-Even Point.

UTILITY ANALYSIS

This section of the paper investigates the revenue and cost effects of large-scale instantaneous adoption of PHEVs from the perspective of electricity demand and costs in the grid for 2003–2004. It does not address any additional benefits or costs of vehicle-to-grid electric power generation or spinning reserve services that PHEVs may provide in the future.

Methods

The analysis of impacts on the electric utilities was conducted on two very different utilities, Cincinnati Gas and Electric Company (CGE), which is located in the East Central Area Reliability Coordinating Agreement (ECAR) North American Electric Reliability Council (NERC) region, and San Diego Gas and Electric Company (SDG&E), which is located in the California and Southern Nevada (CNV) part of the Western Electricity Coordinating Council (WECC) NERC region (see Figure 1 in the Part 1 paper, Kintner-Meyer et al. 2007]. To discuss the PHEV impacts on electric utilities, the paper estimates the impacts on the average total cost and its allocation to generation and T&D as additional electricity is generated or purchased for the support of PHEVs. Two example utilities are discussed—one with substantial fossil fuel-fired base load and load-following generating resources (CGE), and one that is highly dependent on purchased power, largely from natural gas-fired power plants (SDG&E). Throughout the analysis, it is assumed that electricity prices to rate payers are unchanged; thus, decreases in utility average costs would increase profitability, while increases in average costs would decrease profitability. Increases in utility profits could induce rate reductions to rate payers should the regulatory authorities so choose. (Note also that special EV rates could be designed to keep both ratepayers and utility shareholders whole.)

Table 1 shows the characteristics of these utilities in the years 2003 and 2004 (data availability did not allow CGE to be evaluated for 2004). CGE generates more power than it sells to its retail customers (26,938 GWh generated, vs. 20,590 sold at retail). It also wheels and exchanges significantly more than that (total power supply, including wheeling and wholesale, equals over 179,000 GWh), but that additional power is sold at wholesale to a broader market. Based on the typical dispatching pattern of power plants for ECAR, we assume that CGE has the capability of operating its steam electric power plants a higher percentage of the time than it currently does for valley-filling purposes. SDG&E, by contrast, only generates 36.5% of the electricity it sells at retail. All of that electricity is generated by the San Onofre, CA, nuclear power plant. Because nuclear power plants are typically run at 100% of capacity when available, SDG&E would have to purchase any additional electricity it sells for valley-filling from other entities. It is, in effect, a "wires only" utility for purposes of this paper.

The difference between these two utilities also extends to their cost structure and the average cost of power. CGE has an average cost of power production of about $39 per MWh ($0.039 per kWh), of which 40% is variable (mostly fuel), and 60% is fixed. Purchased power costs (all variable) are $33 per MWh ($0.033 per kWh). Transmission costs are approximately $0.50 per MWh ($0.001 per kWh), but are mostly borne by wheeled and exchanged power. Distribution costs are $14 per MWh ($0.014 per kWh) and are virtually all fixed costs. San Diego's (nuclear) own generation costs of $78 per MWh ($0.078 per kWh) are 14% variable and 86% fixed. Its power purchase costs of $70 per MWh ($0.070 per kWh) are all variable, and its T&D costs of $47 per MWh and $85 per MWh, respectively, ($0.047 and $0.085 per kWh), are almost all fixed.

Table 1: Key Characteristics of Cincinnati Gas and Electric and San Diego Gas and Electric

Key Feature	Cincinnati Gas and Electric (Part of Cinergy) 2003	San Diego Gas and Electric (Part of Sempra) 2004
Number of Customers	659,444	1,297,693
Number of Residential Customers	591,050	1,159,634
Total Power Supply (GWh), Including Net Wheeling and Wholesale	179,078	8,448
Total Retail Sales (GWh)	20,590	8,230
Total Residential Sales (GWh)	7,020	3,663
Annual Electric Generation (GWh)	26,938	3,006
Annual Purchased Power (GWh)	152,826	5,472
Average Residential Rate (Revenue per MWh)	$73 per MWh	$146 per MWh
Breakdown of Generation (Annual GWh)		
Steam Electric (Coal or Natural Gas)	26,848	0
Nuclear	0	3,006
Pumped Storage	0	0
Other	90	0
Total	26,938	3,006

Sources: Platts [2005], EEI [2006].

For both utilities, the impact on overall cost and revenue depends on the additional variable cost associated with generating (CGE) or purchasing (SDG&E) electricity to serve the PHEV market and the ability of the utilities to spread fixed cost over more power sales. Average variable costs may rise with increased sales, either because of a shorter supply of electricity at wholesale or because higher-cost generation assets are brought on line, or a combination of both. Average fixed costs will decease, assuming no new infrastructure investment, because the existing debt-service obligation is spread over more MWh sold. As off-peak residential load is added to the system, do the average variable costs rise more than the average fixed costs fall?

To answer this question, we analyze a case that featured substantial market penetration of PHEVs into the residential sector of both the CGE and SDG&E service areas. For purposes of this analysis, we assume that every residential customer has one PHEV. Obviously, this level of market penetration is far beyond what would be expected in the next few years (or, perhaps, even decades), but the case illustrates vividly what the considerations are for electric utilities attempting to absorb PHEVs into their systems. To stay clear of the peaking hours, we assume that all charging takes place during the time period 10 pm to 6 am and that all additional generation will fit into the valley without creating new system peaks. A broad range of battery capacities and recharge requirements is possible. For example, Part 1 of this analysis [Kintner-Meyer et al. 2007] evaluates daily charging requirements from 8.6 kWh to 15.1 kWh per day. For the analysis in this paper, we assume a value toward the upper end of that distribution, 13 kWh per day. For CGE, we evaluated the utility system and hourly demand and concluded that there was more than sufficient off-peak generating and T&D capacity to fully charge one vehicle per residential customer between 10 pm to 6 am on an average day during the summer peak demand season. For SDG&E, which purchases most of its electricity from others, we assume that there is sufficient off-peak power available at wholesale to supply the PHEVs. An evaluation similar to that for CGE indicated that there likely was sufficient 10 pm to 6 am off-peak T&D capacity in the SDG&E system to fully charge one vehicle per residential customer. However, with one vehicle per residential customer, SDG&E off-peak demand approached the overall system peak value, which might mean that T&D capacity, as well as possible additional reserves to meet resource adequacy requirements, would have to be added with 100% market penetration (one PHEV per residential customer). Therefore, we also evaluated SDG&E with a 60% market penetration. The appendix shows the derivation and implications of this additional case.(e)

The following key assumptions for PHEV charging are used:

- Charging time: 10 pm to 6 am (valley-filling) on an average day during the peak summer season.
- 13 KWh per vehicle per night. Average power load per vehicle of 1.625 kW (roughly, 13.5 amps at 120 V alternating current standard service in the home).
- One vehicle per residential customer (100% market penetration). Sensitivity analysis of 60% market penetration was conducted for SDG&E.

Three scenarios are examined.

1. A short run scenario with no change in variable cost including fuel cost.
2. A short run scenario with increase in variable cost due to increases in fuel cost. We assumed that the fuel and other variable resources necessary to generate additional power were more expensive than for current generation and that the additional generation cost was added to the cost of electricity. For CGE, we assumed that the average variable cost of power generation (primarily cost associated with fuel) doubled for the additional generation required. For SDG&E, the baseline cost of natural gas was already very high, so it was assumed that the average variable cost increased for the incremental energy by an arbitrary 50%.
3. A long run scenario with investment for generation. We assume that in the context of the generally growing demand for electricity, the new residential demand represented by PHEVs might require early investment in additional generation. To investigate this possibility, for CGE, we assumed that an additional 600-MW coal-fired power plant would be required at a first cost of approximately $750 million [EIA, 2006]. For SDG&E, which is effectively prohibited by CO_2 emissions standards in California state law from using or importing coal-fired generation, we assumed a gas-fired plant at a first cost of about $350 million [EIA, 2006].

More details on the definition of the scenarios are listed in Table 2.

(e) After this paper was written in January, 2007, the authors were made aware of a similar analysis of vehicle owner and utility economics that was conducted with detailed utility operational information and examined the impacts of a range of charging scenarios [Parks et al. 2007]. The broad conclusions of that study are similar to those contained here.

Table 2: Utility Scenarios Examined

Scenario	Cincinnati Gas and Electric (2003)	San Diego Gas and Electric (2004)
1. Short Run: No Change in Fuel Prices; no Additional Investment	Average Variable Cost: $15.80/MWh (coal-fired) No incremental investment	Average Variable Cost: $57.13/MWh (mainly natural gas-fired) No incremental investment
2. Short Run: Fuel Costs Higher for Incremental Generation	Average Variable Cost: $17.29/MWh (coal-fired). Average variable cost doubles for incremental generation. No incremental investment	Average Variable Cost: $68.37/MWh (mainly natural gas-fired). Average variable cost increases 50% for incremental generation. No incremental investment
3. Long Run: Incremental Investment in New Coal-Fired 600-W(e) Generating Plant	Average Variable Cost: $15.80/MWh (coal-fired) Incremental investment = $750 million	Average Variable Cost: $52.18/MWh (natural gas-fired) Incremental investment = $350 million

Results for CGE

In the short run, the 100% residential market penetration of PHEVs results in an additional 591,000 PHEVs that collectively result in an additional demand of 960 MW between 10 pm and 6 am, or about 2,800 GWh per year. The additional cost of generating and transmitting this power is about $43.2 million, but the average cost of power declines because all of the power is produced and consumed off-peak and contributes no additional fixed cost. As shown in Figure 4, the average cost of power declines from $54 to $50 per MWh in the short run. This cost savings is available either to reduce rates or to increase profits or both. Any rate-making response by the utility and its regulators is beyond the scope of this paper and has not been considered.

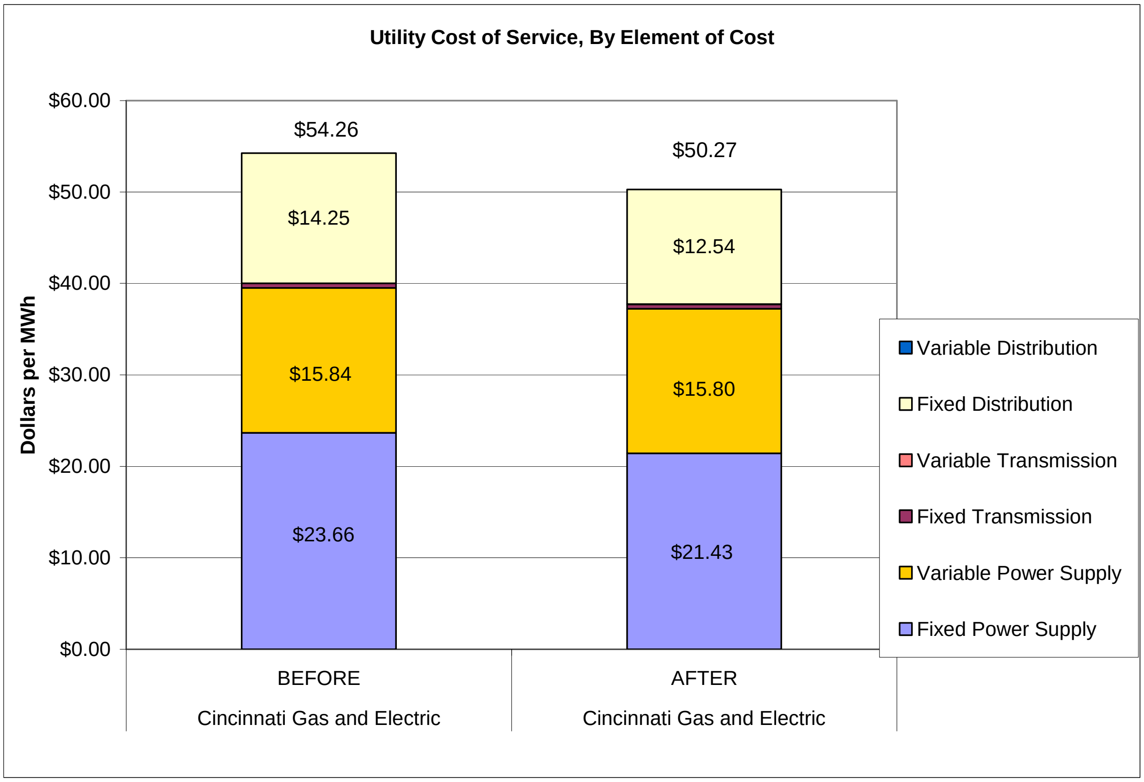

Figure 4: Short Run Impact of PHEV Valley-Filling on Components of System Cost for Cincinnati Gas and Electric

The analysis shown in Figure 4 assumes that there is essentially no change in the average variable cost of generating power in the short run as the PHEVs penetrate the market, and the off-peak demand for power increases. An alternative possibility is that the additional demand could result in more expensive power, either because the utility would be operating less-efficient generating facilities more often or else would have to pay a premium for the additional coal. In Figure 5, we imagine a case where the variable cost of incremental generation doubles because of increased fuel costs. Fuel costs make up 83% of the variable cost. The result of this scenario is shown in the third bar in the Figure 5. Even though the increase in the average variable cost of generation does increase the average cost of electricity by a small amount compared with the base-case, the PHEVs still confer a significant beneficial reduction in the average cost of power.

Finally, the last bar in Figure 5 shows what happens if higher off-peak demand from PHEVs results in a new coal-fired power plant being built, together with the necessity to retire its fixed costs, principal, and interest over 40 years (the resulting annualization of $750 million at an assumed interest rate of 6% is $48.9 million per year) in addition to the already-assumed $43.2 million for extra fuel cost. Here, the economics are not quite as favorable, but the average costs of power still fall to $52 per MWh from $54 per MWh in the base case. A utility with relatively low marginal costs of generation, high fixed costs, and a large difference between peak and off-peak demand can benefit from market penetration of PHEVs.

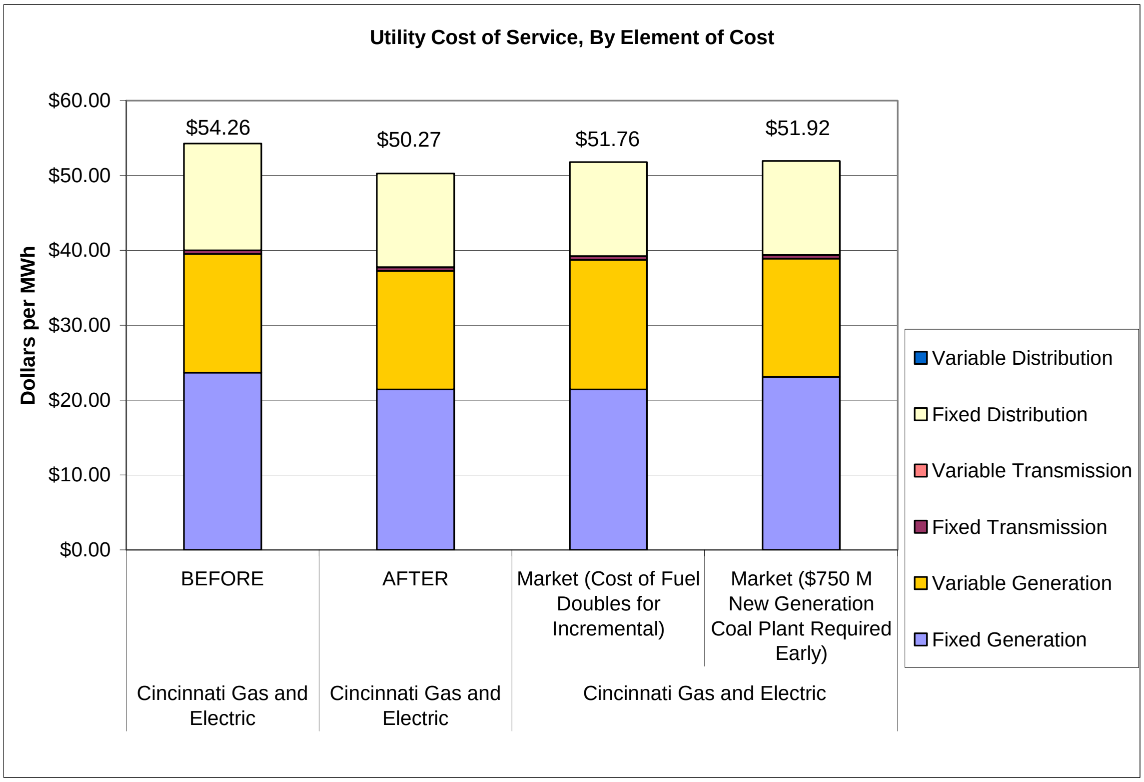

Figure 5: Impact of Alternative Cost Scenarios for Cincinnati Gas and Electric

Results for SDG&E

San Diego Gas and Electric is a net purchaser for over half of the electric power it consumes. Over 36 percent of the electricity sold is generated by one nuclear power plant. The remainder is purchased from others. As market penetration of PHEVs increases, SDG&E would need to purchase the power to serve this market from other generators on the grid. For purposes of this analysis, we assume that SDG&E can do this in the short run at a constant price of about $70 per MWh ($0.070 per kWh), which is consistent with their current average cost for purchased power. Because it is quite possible that the off-peak price in the late evening hours could be lower than the current average price, this price may be conservatively high. This assumption results in an overall average variable cost of power of $57 per MWh (see Table 2). Figure 6 shows the impact of a 100% residential market penetration of PHEVs into the SDG&E service area, about 1.1 million vehicles (this would be about 4% of the California LDV market [DOT, 2002]. Unlike CGE, since SDG&E is in effect a "wires only" utility buying relatively expensive power, the utility gets no cost-reduction benefit from more effective use of its generating facilities and must pay a lot for additional power to service PHEVs. However, SDG&E has a large investment in T&D capital that it is able to use more effectively in off-peak periods, so its overall average cost of power declines from $205 per MWh to $151 per MWh, as shown in Figure 6. In addition, as stated earlier, off-peak purchases may be lower in price than the current average price and could help reduce the average costs of power still further.

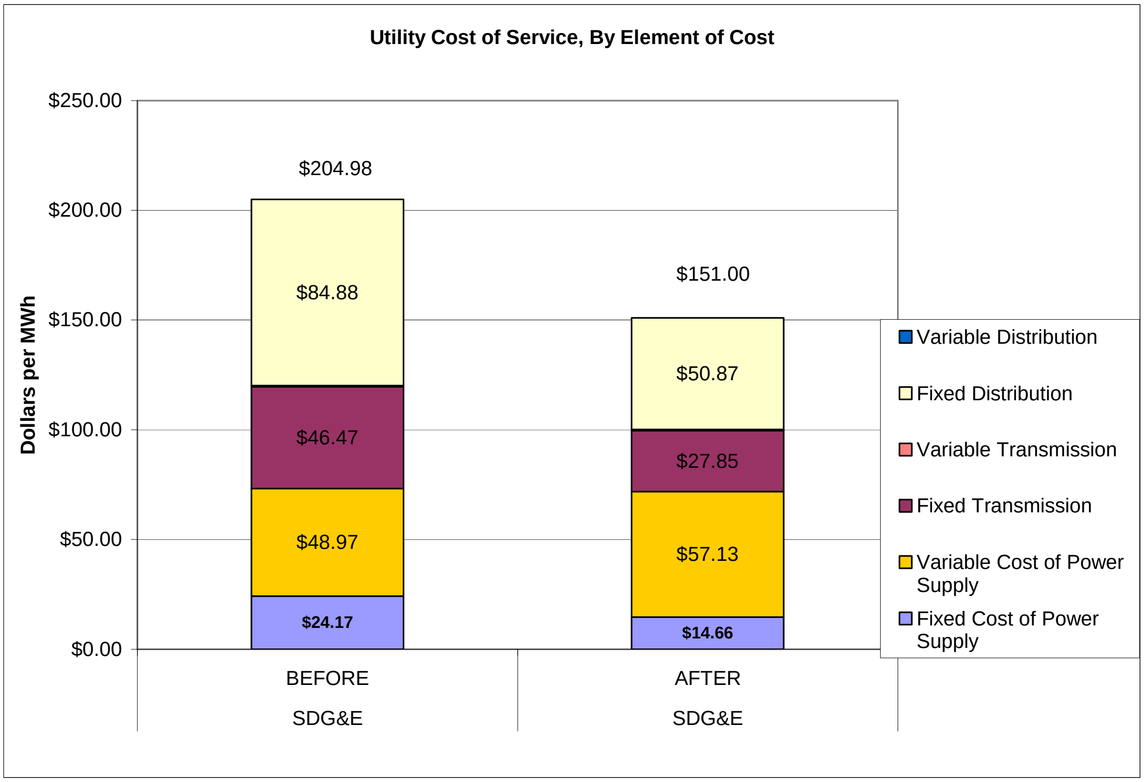

Figure 6: Short-Run Impact of PHEV Valley-Filling on Components of System Cost for San Diego Gas and Electric

In Figure 6, as in Figure 4, we assumed that there is no change in the average variable cost of generating power in the short run as the PHEVs penetrate the market and the off-peak demand for power increases. Figure 7 shows the impacts of all scenarios, including the base-case as a reference. The resulting increase in the average variable cost of generation does put upward pressure on the overall average cost of power in Scenario 2; however, the valley-filling for charging PHEVs still reduces the average cost from $205 per MWh to about $162 per MWh.

The results of Scenario 3 show the impacts of higher off-peak demand from PHEVs, resulting in a new natural gas-fired power plant being built (likely somewhere outside of Southern California), together with the necessity to retire its fixed costs ($350 million at an assumed interest rate of 6%, or $22.9 million per year). For reasons of simplicity, we adopt the average variable costs for the new generation in the base-case example, which reduces the average variable cost overall (although not quite as much as in Scenario 1). Here, the economics are still favorable, largely because the reduction in the average fixed costs of power generation, transmission, and distribution still dominate the increase in variable generation costs. The average cost of power falls from $205 per MWh in the base case to about $153 per MWh.

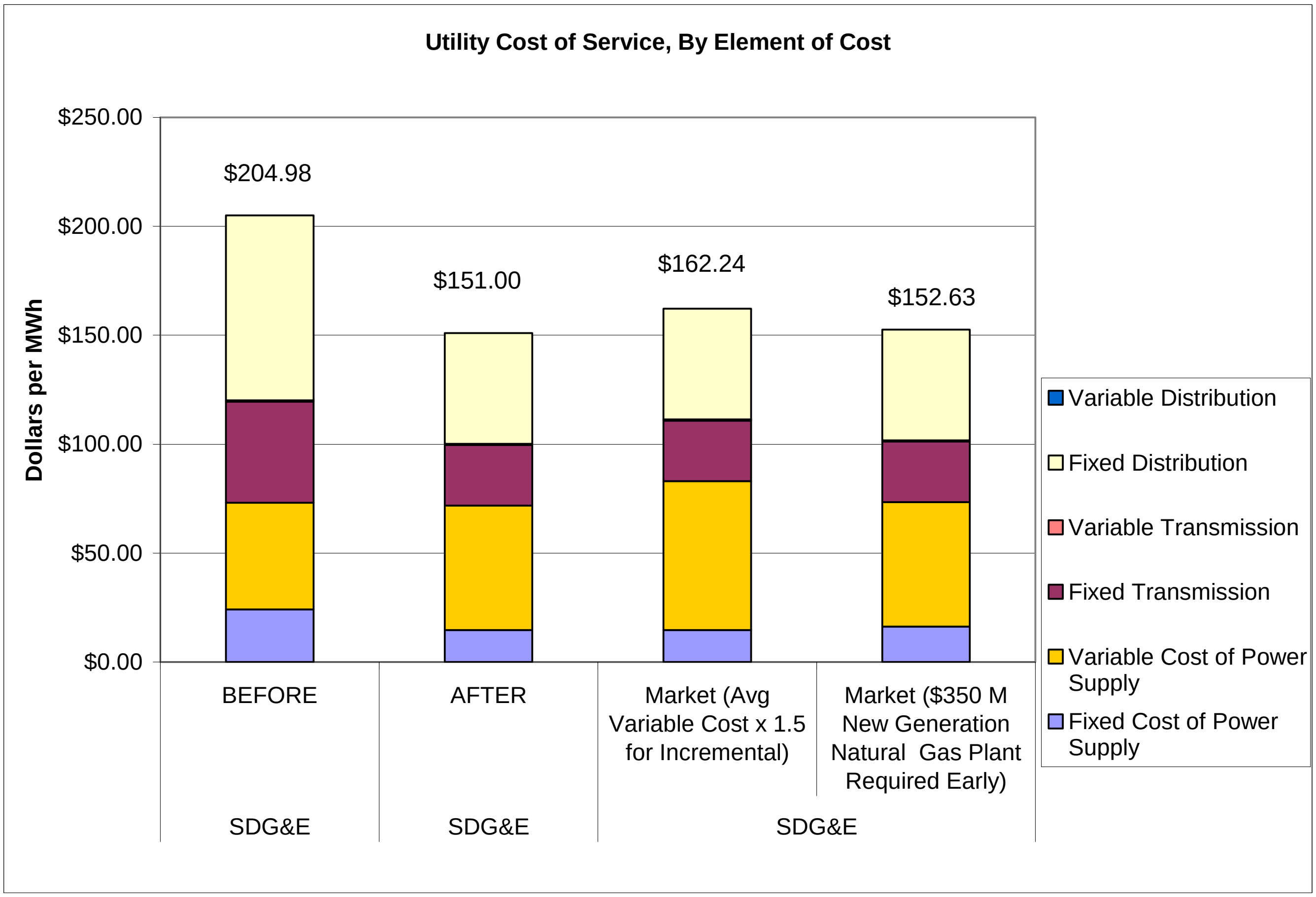

Figure 7: Impact of Alternative Cost Scenarios for San Diego Gas and Electric

DISCUSSION OF RESULTS

The LCC analysis of purchasing decisions shows that at existing average residential electricity rates and over a range of gasoline prices, prospective vehicle purchasers could afford to pay a premium of up to a few thousand dollars over the cost of either a standard 27.5-mpg and/or high-efficiency 35-mpg vehicle and still break even on the life-cycle cost of purchasing and operating a PHEV. The prospective premium is expected to decrease as the cost of electricity increases and the price of gasoline decreases. When compared with an HEV such as the Prius, the economics of the PHEV are not favorable at high electricity prices and marginally favorable at lower electricity prices. This conclusion could change if electric utilities offered reduced electric rates for large blocks of electricity purchased off-peak (and possibly increased them on-peak). The utility analysis indicates that large-scale market penetration of load-leveling off-peak PHEV charging could reduce utility system average costs of power and make such preferred rates a possibility.

Based on our examination of two very different electric utility circumstances, it appears from the utility analysis that under reasonable assumptions, a high rate of market penetration of PHEVs can achieve significant load leveling, improve the efficiency of the use of fixed capital, and provide significant average cost savings for a wide variety of electric utilities. We do not directly address the implications for rate-making, which is still cost-based in many parts of the country, or the impacts on profitability, but there likely would be enough money to share between ratepayers and stockholders, or as indicated in the previous paragraph, to offer incentive rates for PHEVs. The major tradeoff for electric utilities with PHEVs is always whether the average variable costs associated with the additional generated or purchased power necessary to serve the PHEVs are greater than or less than the reduction in average fixed cost achieved by spreading fixed costs over more kWh. Viewing the two very different electric utilities discussed in this paper, we notice that the most advantageous conditions for PHEVs are where the utility in question has

- high fixed unit costs and low variable unit costs of generation
- considerable spare off-peak capacity or access to low-cost purchased power.

However, the San Diego Gas and Electric example illustrates that under the correct circumstances, PHEVs and valley-filling can even be helpful in an (almost) wires-only utility that has a high variable cost of power.

CONCLUSIONS AND FUTURE WORK

PHEVs have the prospect of entering the U.S. electrical grid, but whether they ever do so in large numbers will depend in part on their relative economics compared with more conventional transportation choices as well as their impact on utility economics, which likely would affect the prices charged for their fuel (plug-supplied electricity) and arrangements made by utilities to accommodate their recharging. The analyses conducted for this paper show that the economics for both the prospective vehicle owner and the electric utility are promising and that more detailed analysis could more completely identify and evaluate opportunities.

Much research yet remains to be done. For example, the analysis conducted in this paper assumes that charging a PHEV would be a relatively simple affair with each vehicle plugged into a home circuit, probably governed by an on-board timer that allows only late-night charging. Much more elaborate grid-smart “smart charging” systems that could optimally and instantaneously match PHEV charging to the real-time condition of the electric grid and possibly allow V2G applications are the subject of current research and development. The analysis in this paper has yet to be conducted for such systems, including their costs and a realistic technical and economic assessment of their likely effects on the grid. In this paper, we also have assumed that the host utility and the grid have to make only minor accommodations to absorb a substantial number of vehicles. However, the relationships between the grid as a whole, generating companies, regulators, and retail electric utilities all have become extremely complex in the last 10 years. It is not at all certain in the case of wires-only utilities that they would be able to contract for relatively inexpensive off-peak electricity from generating entities to charge PHEVs without bidding up the price of such electricity. In the case of utilities that own their own underused generating plants, it is not obvious that they would run these generating plants to meet the expanded off-peak demand from their residential customers if other, more lucrative, market opportunities were available or if running these plants were far costlier than their “average” plant as shown here. In summary, while more economic analysis needs to be done using production-cost approaches with regional power systems or individual electric utilities along with utility economic data, this paper illustrates the general economic proposition that off-peak power revenues from PHEV owners could be attractive and beneficial for both the electricity service provider and the rate payer.

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APPENDIX A: IMPLICATIONS OF A 60% MARKET PENETRATION OF PHEVS FOR SAN DIEGO GAS AND ELECTRIC SERVICE AREA

With one PHEV per residential customer discussed in the text of this article, SDG&E demand approached the overall system peak value, which means that T&D capacity might have to be added to cope with 100% market penetration. Therefore, we also evaluated SDG&E with a 60% market penetration. This value was derived by taking the current system peak from the hottest day and subtracting the actual demand on an average summer day in each hour between 10 pm and 6 am. This determined the approximate level of extra hourly demand that could be fit under the system peak if it were to occur during the hours of 10 pm to 6 am. We then calculated the number of vehicles that could be simultaneously charged with that electricity, which resulted in a market penetration of 61% of residential customers. This was rounded down to 60%. Although this would result in a new nighttime "peak" on an average summer day, it still would be less than the current system peak on the hottest days and should therefore be possible to serve with existing T&D resources.

Figure A.1 shows the impact on the components of average system costs. Overall, the average cost of power declines.

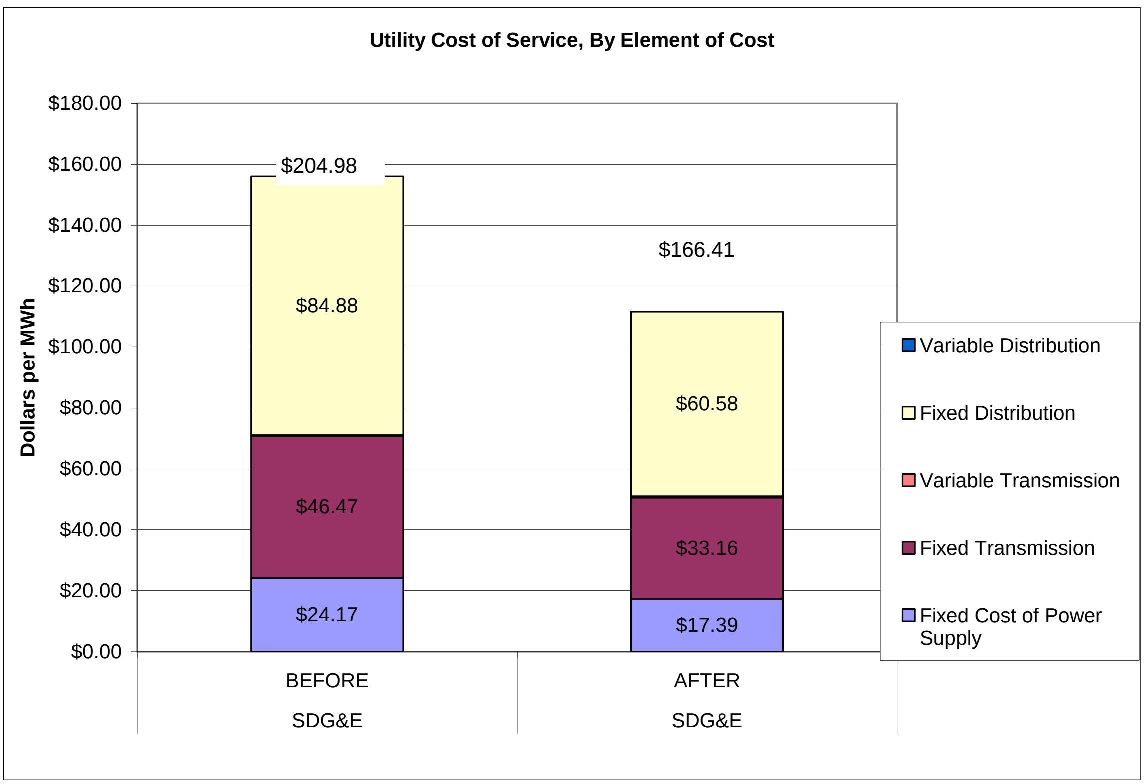

Figure A.1: Short Run Impact of PHEV Valley-Filling on Components of System Cost for San Diego Gas and Electric with 60% Market Penetration of PHEVs

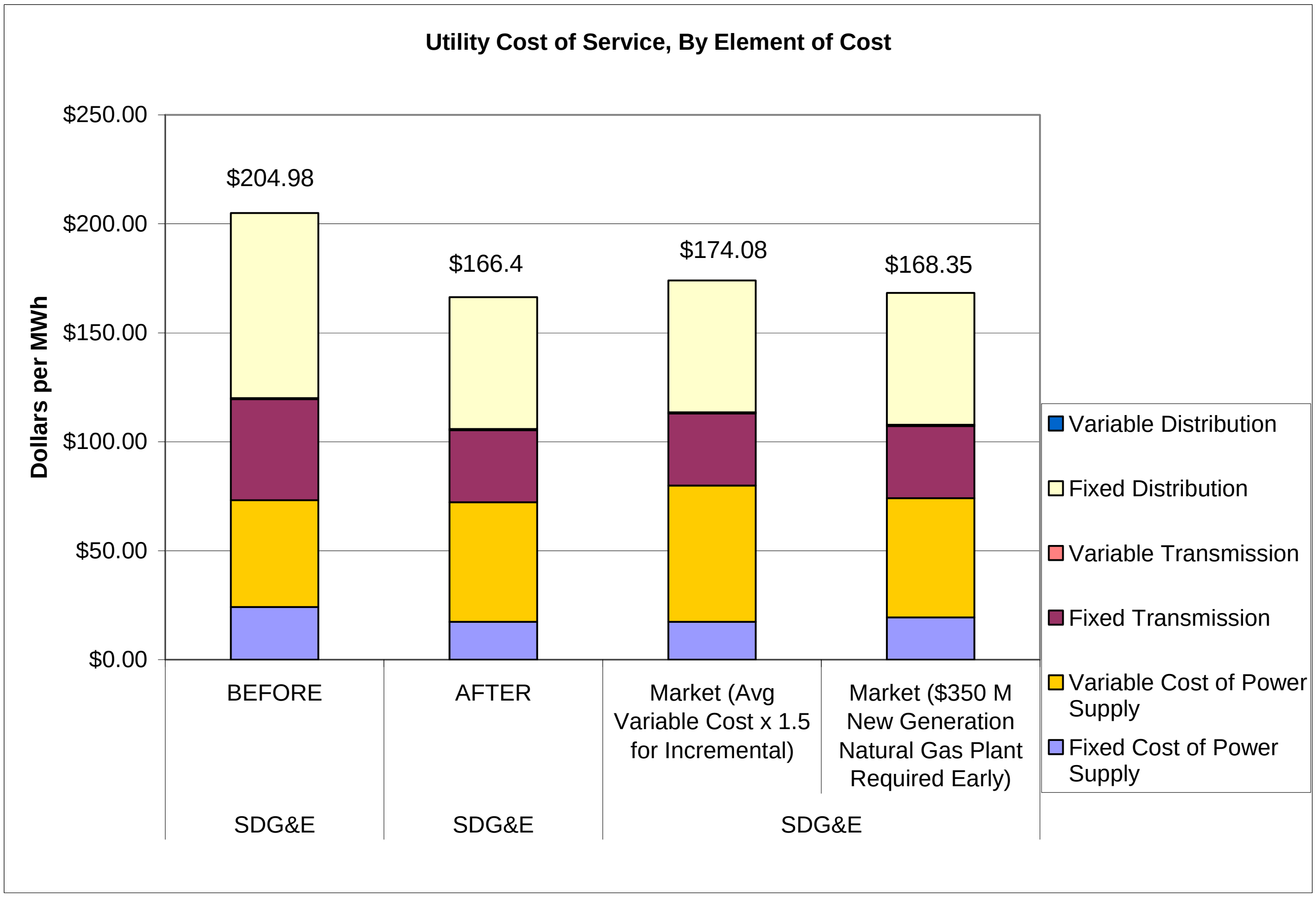

Figure A.2: Impact of Alternative Cost Scenarios for San Diego Gas and Electric with 60% Market Penetration of PHEVs