As required by the 2016 Demand Response Cost Effectiveness (DR CE) Protocols, SDG&E is providing this qualitative analysis of non-energy and non-monetary benefits and costs of Demand Response (DR) in its workpapers on cost effectiveness. The protocols require SDG&E to include numeric values for these inputs if and when it is possible to estimate quantitative values for any one of them for a specific DR program. The DR CE protocols specifically require consideration of

1. Participant non-energy benefits or costs, such as improved ability to manage energy use and “feeling green.”
2. Market benefits or costs, such as market power mitigation and market transformation benefits.
3. Social non-energy benefits or costs, such as environmental benefits, job creation benefits, and health benefits.
4. Utility non-energy benefits or costs, such as fewer customer calls and improved customer relations.
5. **Definition of Demand Response**

The qualitative analysis is limited to DR defined as a change in end-use electricity usage in exchange for a capacity, energy, and/or ancillary services payment. Excluded from the qualitative analysis is “demand response” created by behind-the-meter (BTM) generation, whether renewable or non-renewable; behind-the-meter storage; and customer response to time-of-use rates. The Commission has discouraged the use of back-up generators in demand response programs, so this analysis does not consider the different qualitative benefits and costs of demand response provided by BTM generation. The analysis of storage and its multiple uses is complicated.[[1]](#footnote-1) Since it is difficult to isolate the qualitative benefits of storage used as DR separate from other applications, because there is an increased use of energy with storage, and because the lifecycle environmental benefits and costs depend on the type of storage technology, non-energy and non-monetary benefits and costs of storage are not addressed. And lastly the types of DR considered in this application do not include general customer price response to time of use (TOU) rates, as is being discussed in the Residential Rate OIR, or Critical Peak Pricing (CPP) rates.[[2]](#footnote-2) The analysis of the price response to rate design, if done correctly, is a response to more accurate price signals, a type of DR that is not the focus of demand response considered in the application. While not considered, it is likely that response to accurate price signals has similar qualitative benefits as other DR.

Because of the inability of utilities to provide real-time pricing, utility DR programs and now third-party DR programs have been developed to reduce usage at times of system peaks. While new types of DR are being considered to address renewable energy integration, the proposed set of DR programs in this application are primarily designed to reduce usage in the one percent of hours each year when the California Independent System Operator (CAISO) system, the local SDG&E area, or in some cases the distribution system may be stressed due to insufficient generation, transmission, or distribution, respectively.[[3]](#footnote-3) Because of the unique nature of DR replacing distribution infrastructure (and the fact that it is being discussed in the distributed resource planning proceeding), this qualitative analysis excludes discussion of non-energy and non-monetary benefits and costs related to avoided or deferred distribution infrastructure. In addition, given that the more immediate generation needs are likely local generation capacity needs for SDG&E, this qualitative analysis excludes discussion of non-energy and non-monetary benefits and costs related to avoided or deferred transmission infrastructure.

The qualitative non-energy and non-monetary benefits and costs of DR are thus limited to 1) the external effects of reducing energy at times of system or local needs, and 2) the reduction of future needs for generation resources (capacity) to meet system peaks. Discussion of new types of DR and new models are under discussion in response to the DR Potential Study, but are outside the analysis presented here.[[4]](#footnote-4)

In the following analysis, per Commission direction, it is assumed that load-modifying DR has energy benefits only and so any qualitative benefits of deferred capacity are not considered. Further, the qualitative analysis assumes all DR programs reduce energy use. To the extent that customers simply shift consumption to a different time period (as is the assumption in the response to TOU rates), the qualitative social benefits associated with assumed energy use avoided are reduced. Lastly, the qualitative social benefits of avoided generation assume that fossil generation capacity is avoided, per the DR CE Protocol direction, even though the RPS and Commission policy suggest that additional fossil generation may not be needed for a long period into the future and may not be the resources avoided.[[5]](#footnote-5)

1. **Analysis Criteria**

To comply with the DR CE protocols, SDG&E first determined if the qualitative benefit or cost has been addressed in a study supported by the CPUC, such as the DR Potential Study. If the study quantified the effect, SDG&E used the quantified qualitative benefit. For example, the CPUC’s DR Potential study addresses both market transformation and customer non-monetary benefits in its medium scenario case that forms the baseline of DR Potential estimates, so the values assigned to qualitative factors in that study are utilized here. For social costs related to air pollution, SDG&E uses values previously developed by E3 and used in Commission-approved cost effectiveness analyses. For other benefits and costs, SDG&E conducted a search of the academic literature to determine if the effect had been discussed. If there is no academic literature discussing an effect related to DR, SDG&E assumes it does not exist. If there is academic literature, the next step is to determine whether it is applicable to DR. If it is applicable to DR, the analysis is summarized and a determination is made whether the effect is quantifiable.

1. **Qualitative Benefits Analysis**

The purpose of this qualitative analysis is to better understand the impacts of DR on the electric grid and customers that may or may not be quantifiable.

1. **Participant Non-energy Benefits and Costs**

The participant non-energy benefits and costs include the intangible benefits or costs that DR participants often perceive when they agree to reduce their demand during DR events. The primary reason for offering an incentive payment for DR is the loss of production an industrial customer may experience, and the inconvenience or discomfort a commercial or residential participant may experience. There is likely a distribution of these costs across the range of customers. In addition, some customers may receive other non-monetary benefits such as the benefit of “Feeling Green.” Some customers would consider this a real benefit of DR and be willing to accept a lower payment for participating in a utility or third-party DR program. Likewise, there may be a subset of customers who receive value in “keeping the lights on” and would be willing to accept a lower payment to participate in a DR program. The sum of all these benefit and cost effects is a willingness for customers to participate at different levels of incentive payment.

The DR Potential Study sheds light on this element through regression analyses of customers’ willing to participate at different incentive levels. The graphical result below from Appendix F of the DR Potential Study Phase 2 suggest that the default value for customer costs for Large Commercial and Industrial (C&I) DR programs of 75 percent of the incentive is about right. The area under the curve is about 75 percent of the rectangle at a given incentive level (the amount if everyone had the same level of participant cost at 100 percent of the incentive level). As it shows, some customers would be willing to participate at a lower level of incentives. The graph also highlights that as the level of inconvenience increases with more hours of DR energy reduction, the DR program participation level declines by two-thirds at a given level of incentive if the number of hours of energy reduction increases from 10 hours per year to 100 hours per year.



The graphical result below for Small and Medium Commercial and Industrial (C&I) DR programs likewise suggests that the default value for customer costs of 75 percent of the incentive may be about right for incentives up to $100/kW-year. The area under the curve is more than 75 percent of the rectangle for values above 100 kW-year given the relative flatness of the curve. The graph also highlights that as the level of cost increases with the cost of installation of a technology, participation rates decline substantially. Any psychic benefits of launching new technologies are apparently small compared to the added costs of the new technology including the costs to learn how to effectively use a new technology.



The DR Potential Study analysis also shows the residential customer costs are lower than for C&I customers as participation rates at a given level of incentive are higher. That is, residential customers can be offered a lower incentive than C&I customers to achieve the same participation level percentage. The graph also highlights that as the level of cost increases with the installation of a technology, participation rates decline substantially less for residential customers than for small and medium commercial. It is not clear whether the costs of the technology are less for residential customers (including the costs to learn how to effectively use a new technology) than small C&I customers or whether residential customers have greater psychic benefits of launching new technologies.



The customer propensity to adopt DR technologies is the likelihood of customers to adopt DR technologies relative to the baseline estimate that is based on historical relationships to eligibility, incentives, marketing, and customer characteristics. The DR Potential Study assumes that customers will be 30 percent more likely to adopt DR technologies in 2025 than in 2014 in the medium case given the same eligibility, incentives, marketing, and customer characteristics.[[6]](#footnote-6) This is a quantification of the qualitative customer benefits and costs that may change in the future. The DR Potential Study assumption is that customer costs (information costs, transactions costs, and/or inconvenience costs) can be reduced over time, creating a 30 percent increase in participation at a given level of incentive.

In addition, for technologies that have more than one use, the qualitative analysis includes the reduction in participant cost for DR related to the potential co-benefits.[[7]](#footnote-7) The same technologies or device upgrades that enable DR (e.g., smart thermostats, building EMS, or lighting controls) produce other cost benefits by allowing a building to operate more efficiently. The DR Potential Study assumed 33 percent co-benefits for most end uses (residential air conditioning smart thermostats, commercial HVAC with EMS, and refrigerated warehouses). The Study also assumed co-benefits of 75 percent for lighting (luminaire and zonal), which has controls typically installed to receive energy savings benefits. For variable frequency drive pumps or motors for agriculture, wastewater pumping, and wastewater process, the Study assumed a co-benefit of 75 percent from energy savings like the DR Potential Study.

SDG&E has included co-benefits in its base analysis by excluding technology or device costs in excess of the incentive payment. Therefore, the qualitative co-benefits identified in the DR Potential Study are not included here to avoid double-counting.

**2. Market Benefits and Costs**

**Market Power Mitigation and Price Suppression.** The market price benefits or market price effects, alternately called “price elasticity effects” or “market effects,” are the reduction in wholesale market prices that occur as a result of the reduction in demand due to DR programs. Corollary benefits cited in the literature included reduced market price volatility (alternately called “hedge” or “insurance” value) and increased reliability.[[8]](#footnote-8) In California, this market price benefit was required for cost benefit analysis of Energy Efficiency (EE) programs by California Assembly Bill 970 and specifically incorporated in 2004 EE cost benefit analysis by E3.[[9]](#footnote-9)

The focus of this section is how the market price benefit of DR relates to the level of reliability compared to any other separate and distinct impacts of DR. If changing the level of reliability through equivalent supply side resources would have a similar effect on market prices, market price volatility and system reliability, DR programs would simply be alternatives to supply resource necessary to achieve the same level of reliability. If this is the case, the DR resource should convey the same value as conveyed by the deferred supply resource and have no added qualitative benefit.

The electricity market is characterized by three important characteristics. First, electricity cannot be economically stored so that supply and demand must balance in real time. Second, the demand for electricity varies dramatically from day-to-day and hour-to-hour based on changes in the activities of businesses and residences and the output of variable renewable generation. And third, the supply of electricity is highly capital-intensive and effectively fixed at some level in the short-term.

As a result, power system operators plan to have enough supply resources available to handle the fluctuations in demand net of variable renewables. For the hour-to-hour and moment-to-moment balancing, the system operator acquires resources to have on standby in the ancillary services market. For the longer-term daily and monthly fluctuations, the system operator has available resources needed provided by “resource adequacy” resources. The amount of resources needed in excess of average peak loads is referred to as the “planning reserve margin” and is generally in the range of 15 - 20 percent of expected peak load depending on the underlying variability of the demand and the perceived consumer cost of forced curtailment. The planning reserve margin is associated with a desired level of reliability by customers as determined by regulators, but in California it has also been affected by the large increase in renewable generation based on Renewable Portfolio Standards (RPS) unrelated to load growth or retirement of existing facilities. As a result, as pointed out in the Demand Response Potential Study, there is currently an excess of supply resources available and a very large reserve margin.[[10]](#footnote-10) The size of the reserve margin will have an impact on market prices in extreme demand conditions. With a low level of planning reserves, there is a higher probability that shortage conditions may exist and prices may spike. The larger the reserve margin, the less likely it is that an extreme level of usage will exceed the capacity of existing resources and the lower the probability of shortage conditions.

Pursuant to the Energy Policy Act of 2005, the U.S. Department of Energy developed a study, “Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them.” (DOE Study) that examined the benefits of DR under different time frames and different market structures.[[11]](#footnote-11) Appendix B of the DOE Study provided a detailed analysis of market price benefits. The DOE analysis found that in regions with wholesale markets, the introduction of supply-side DR provided short-term market price reductions. The expansion of DR, other things equal, would lead to market price reductions as peak demand is reduced. Lower peak demand and the non-linear shape of the electric supply curve also would reduce market price volatility.

The DOE Study does also provide a sidebar discussion on whether market price benefits are permanent, citing the argument that in long-run equilibrium in the energy market, lower prices requires some exit by generators and a return to higher prices.[[12]](#footnote-12) The resulting long-run equilibrium after some exit by generators would be a return to the original prices.[[13]](#footnote-13) In markets with RA requirements, the effect of energy market price suppression is expected to be increases in payments for RA, to keep adequate resources online.

The DOE Study pointed out that DR that is part of the planning reserve margin does not provide incremental reliability benefits, stating “it supplants conventional resources in meeting established reliability goals, simply replacing what a generator that was not built would have provided.”[[14]](#footnote-14) Since California has adopted a bifurcation and preference for supply-side DR, this DR would lead to 1) an increased reserve margin, or 2) a reduction in new supply-side resources, simply replacing conventional generation in the planning reserve margin.

The market price benefit of DR is identical to the effect on market prices of a similar increase the reserve margin achieved by adding new supply resources. The higher level of reserve margin impacts market energy prices in periods of extreme demand, reducing shortage prices. In turn, measured price volatility is reduced given the non-symmetric shape of the supply curve. Since supply resources are an alternate way of meeting the reserve margin, if an avoided supply resource is part of the cost benefit calculation of DR, there is no added long-term market price effect since there is no change in the reserve margin. The market price reduction benefit can be achieved equally well by any increase in the reserve margin, whether through added DR or incremental supply resources.

SDG&E does consider the short-term effect on market prices consistent with FERC Order 745. As long as the bid price of DR resources is above the net benefits test price, there is no compensation to the load-serving entity for energy not purchased at the retail rate. The net benefits test price is the price in the wholesale market where DR can have a price suppression effect.

Bottom line, SDG&E does not calculate any qualitative long-term market price effects since DR is no different than supply-side resources, and short-term price effects are considered in the base analysis by not deducting the loss of revenue and imbalance fees the load-serving entity may incur.

**Market Productivity Gains.** DR may provide a benefit beyond the reserve margin effect; there may be an efficiency effect achieved when retail customers implicitly are dispatched at a price closer to the marginal cost instead of an averaged price. DR participants consume less at a marginal price that is higher than an average price. The value of welfare gain is approximately equal to one half of the difference in usage with the price responsive DR compared to usage without price responsive DR multiplied by the difference in the market price without price responsive DR and the average price the customer sees with DR. The qualitative benefit could be estimated, but is not given that pricing program DR (TOU rates and CPP rates) are outside this analysis. It would be appropriate for programs like Demand Bidding, but that DR program is being phased out.

Efficiency gains are increased if generators have market power during extreme peak periods. In extreme peak conditions, one or several suppliers may be large enough to be pivotal suppliers. This effect, though, has been mitigated in CAISO markets based on current CAISO rules, and so may be small. In addition, it is also true that supply side resources owned and operated by independent generators with low market shares could provide the same reduction in the probability of conditions where there may be pivotal suppliers. Therefore, this qualitative benefit likely does not occur.

**Increased Generation Diversity.** Supply-side DR that avoids new generation capacity provides additional value by increasing diversity of supply, avoiding new generation capacity dependent on natural gas. If there are natural gas supply shortages during cold winters or in summer due to lack of available natural gas storage, DR can be used in place of natural gas-based electric generation. Given the recent increases in natural gas reserves in the U.S., this portfolio benefit would likely accrue only to DR programs available in the winter, like the Base-Interruptible program, where there would still be a probability of natural gas shortages, although a low probability. Given the low and uncertain probability of natural gas shortages, this qualitative benefit is not quantified.

**Uncertain DR Amounts due to Uncertainty of Measured Response.[[15]](#footnote-15)** DR programs pay consumers to reduce their consumption relative to some administratively set baseline level of consumption creating the serious challenge of measuring what the consumer would have consumed without the payment. It is impossible to observe the counterfactual consumption level because we cannot measure something that did not happen. If the customer receives payment for a demand reduction during the hour, the only quantity that can be observed is the customer’s actual consumption with the payment. Determining what the customer’s consumption would have been without the payment must rely on a statistical model of the customer’s behavior to estimate this counterfactual consumption.

This problem is often described as the “baseline” problem. The baseline problem can often be broken down into a general measurement problem, an adverse selection problem, and a moral hazard problem. The general measurement problem arises from the fact that, when paying for reductions, the “buyer” of demand response does not know precisely what the consumer would have consumed in the absence of a DR payment. Even the best statistical model of a customer’s hourly electricity consumption behavior as a function of hourly prices and all observable customer and weather characteristics are only able to explain a fraction of the variation in that customer’s consumption of electricity across hours of the year. Consequently, even assuming that the best model of the determinants of each customer’s electricity consumption is available, it is impossible to determine accurately what that customer would have consumed in the absence of the payment. This problem is lower in the industrial customer case where energy use is highly correlated to production and is higher in the small C&I and residential customer segments where usage changes dramatically with temperature.

While the errors may not be biased in one direction or another, more or less DR may be supplied at any time simply because of baseline measurement error. This problem can be minimized by finding better statistical models, but likely will never be eliminated. This qualitative cost of uncertainty of response is not quantified.

Adverse selection, on the other hand, is biased in one direction. Because of the inability to be 100 percent accurate in determining the baseline, a DR program may make a payment to customers who would have reduced their consumption even without a payment. For example, a business that closes for random week in the summer, or a residential customer who always goes to the beach on hot days.

The moral hazard problem arises whenever customers are rewarded for having higher baselines. Put simply, firms and customers have an incentive to inflate the level of their baseline, because they are paid based upon the comparison of their actual consumption to this baseline. In many cases, customers can be given a perverse incentive to over-consume as a means to inflate their baselines. For example, when customers have the opportunity to consume all they want at a standard fixed retail rate, and then sell back reductions from that level at the real-time price in an ISO market, there is an incentive to raise consumption in order to increase the level of the “reduction,” which is rewarded at a much higher price. Even perfect measurement of consumption does not eliminate the moral hazard problem with regards to baselines. The problem is created by an underlying rate structure that provides asymmetric prices for consumption and DR reductions.

The qualitative effects of both adverse selection and moral hazard can undermine the reliability of DR, as less reliable than an equivalent amount of generation capacity. This in turn can result in the CAISO purchasing backstop capacity resources, inflating costs to consumers. It is unclear how this qualitative effect would be measured and to what extent it may be prevalent in DR programs including the DRAM program, so it has not been quantified.

**Reduced DR Amounts Achieved Due to Customer Fatigue.** DR is unlike a combustion turbine in that more calls for DR load reductions can lead to a serious degradation in performance of a demand response resource in the short-run, and reduced customer participation in the long-run. The DR Potential Study documented the long-run effect, showing participation rates greatly depend on the number of hours of load reduction required: from 35 to 45% participation with 1 or 2 hours of load reduction to 10% participation with 40 hours of load reduction.



SDG&E DR programs, except the BIP program, have fairly high requirements for the number of hours of actual load reduction created by the design of the triggers. It will be interesting to see the DRAM results to compare the average numbers of hours of load reduction occurring in utility DR programs versus third-party programs like DRAM.

The maximum number of hours of load reduction and the program triggers are DR program parameters that impact customer costs and expected customer participation and so are indirectly included in the DR cost effectiveness in the assumed expected participation rates, and so the qualitative effects are already considered in DR cost effectiveness except for the DRAM program.

**3. Non-Energy and Non-Monetary Benefits and Costs**

**Environmental Impacts.** One social benefit considered quantitatively is the environmental impacts that might be avoided by DR. For this analysis, SDG&E breaks the analysis into avoided energy benefits, assuming that energy is avoided by DR and not simply shifted into other time periods, and capacity benefits, environmental benefits from not building an additional air-cooled advanced combustion turbine in the San Diego area to meet peak demand.

To estimate energy benefits, SDG&E assumes the avoided energy would be from an existing combustion turbine located in the SDG&E service area with a heat rate of 12,500 btu/kWh (roughly the emissions rate of the least efficient CT in the area operating at a high outside air temperature). Environmental benefits related to reduced energy use include decreased costs associated with air pollution assuming the avoided energy would be produced in the local SDG&E area. There is a very robust literature on the environmental benefits of avoided local air quality benefits, but rather than try to assess the range of benefits, SDG&E uses the values from E3 for criteria pollutant emissions costs that have been previously calculated and used in the avoided cost calculator.[[16]](#footnote-16) SDG&E does not include a GHG cost adder since GHG costs are implicitly included in the market price of energy as documented by the CAISO.

2018 Environmental values Price/lb. Emission Rate Price/MWh

NOx $2.481/lb. 0.2320 lbs./MWh $ 0.577/MWh

Particulate Matter $795/lb. 0.0896 lbs./MWh $ 71.232/MWh

In addition, SDG&E also includes one-third the renewable premium in the avoided cost calculator in the energy price as renewables costs are avoided by avoided energy. The 33 percent Renewable Portfolio Standard (RPS) and the future 50 percent RPS renewable requirements were adopted to reduce GHG.

2018 Renewable Premium - $47.59/MWh x 33% = $15.86/MWh

To estimate the capacity benefits, SDG&E assumes the deferred resource would be located at a brownfield site in the SDG&E service area similar to the utility-owned Miramar combustion turbines (CTs) or the procured Carlsbad CTs. Those benefits related to reduced need for new generation include biological impacts; impacts on cultural resources; diminishing visual resources (e.g*.,* due to power plant stacks); land use, including impacts of energy infrastructure on local ecosystems; and impacts on noise pollution. Because of the assumption of use of a brownfield site, there are minimal qualitative benefits from avoided capacity. Any environmental justice improvements from avoided generation in disadvantaged communities are also excluded since recently passed legislation discourages the location of fossil generation in disadvantaged communities.[[17]](#footnote-17)

**Job Creation Impacts.** The qualitative benefits of job retention benefits from more accurate price signals are not considered. To the extent customer rates are high due to inaccurate price signals, there may be an incentive for a business to leave the utility and California. DR meant to provide an offsetting subsidy to businesses is not considered.

The job creation benefits considered would be those over and above the job creation benefits of a constructing combustion turbine plus the job reductions related to reduced spending by non-participating customers since in the near-term DR is more costly than alternative generation as demonstrated by the DR Potential Study.[[18]](#footnote-18)

There are not likely any jobs created from customers simply reducing usage, but there may be jobs created at the utility to support the demand response programs and at companies providing third party aggregation services. In addition, new control technologies used to create demand reductions may create jobs. On the other hand, jobs constructing and operating combustion turbines would be lost. If there is no deferred CT, DR programs are generally not cost effective as the increase in rates has a negative impact on jobs, especially in disadvantaged communities, as documented in the recent CAISO analysis.[[19]](#footnote-19)

**Market Transformation.** Change in the market for the technology from learning-by-doing can lead to lower prices for a DR technology in the future. In 2005, the CPUC adopted the California Solar Initiative, committing the State to $2.8 billion in direct subsidies for solar photovoltaics and solar water heating in addition to the direct subsidies provided by the Emerging Renewables Program (ERP) and the Self Generation Incentive Program (SGIP). Indirect subsidies afforded by net energy metering were also in the billions of dollars over the last decade. The CPUC stated in D.05-12-044, “Significantly, the benefits of solar technologies also motivate us to transform the existing market in a way that makes solar products cost effective without incentives.” Later in the same decision, the CPUC stated, “Because we believe solar technologies hold some promise of becoming a cost-effective, reliable source of energy in California, we state our intent to adopt a solar incentive program that builds on the existing SGIP program and the CEC’s ERP program.” The CPUC’s decision recognized that solar photovoltaics were not cost effective using the standard cost effectiveness tests, but held to the belief that there was a potential “to transform the existing market” so that solar technologies would become cost effective.

 A similar question is whether there are “market transformation” benefits with DR technologies. The term “market transformation” has been described as permanently changing the probabilities of selection of elements from the choice set. This definition provides a clear test as to whether market transformation interventions do, in fact, have an effect on the market. First, an intervention must permanently change the probability of selection. It is clear that subsidies for products will alter the probability of their selection, but market transformation occurs only when the selection probability is altered even after the intervention is withdrawn from the market. In an example from the energy efficiency area, this type of market transformation occurred in the 1980s with refrigerators in California. New energy efficient refrigerators were subsidized through utility programs, leading to manufacturers increased production of efficient refrigerators, thus providing additional refrigerator choices for consumers. Once the new products were perceived to be viable alternatives (a non-zero probability of selection without subsidies), the choice set was permanently changed by regulation in California, removing highly inefficient competing products from the choice set. Electricity consumption of refrigerators in California has declined by 75 percent over a 25-year period.[[20]](#footnote-20) More recently California’s experience with compact florescent light (CFL) bulbs and light emitting diode (LED) light bulbs are examples of market transformation.

The detailed process for assessing California energy efficiency market transformation programs is also described in the 2004 document, “California Evaluation Framework.” prepared for the CPUC. [[21]](#footnote-21) The first step outlined in the guide is to develop the theory to the causally link the intervention and the effect. In most energy efficiency market transformation studies, the causal link theories that have been prevalent are based either on a market barriers theory or a diffusion of innovation theory.

For the market barrier approach, the market and market structure are identified including the significant barriers. A hypothesis is developed as to how and why the market intervention will reduce the barrier long-term to change selection probabilities. For the diffusion of innovation approach, the analysis posits a rate of adoption of the new technology and estimates how the market intervention will alter that rate of adoption over time. In the market barriers approach, the market intervention would move the customers’ cost-benefit trade-off closer to a societal cost-effectiveness over time as the market invention reduces or eliminates the barrier. Residential DR would be chosen except for the market barriers. If residential DR was able to be activated without human intervention, transaction costs would be reduced and more DR would be chosen. The dynamics relate the increased customer adoption rates to the reduction in market barriers associated with bundled attributes.

Likewise, in the diffusion of innovation approach, the starting point assumption is also that the consumer would participate if only they were aware of the significant benefits of DR. If there were more awareness about DR reduction in bills, benefits to the electricity grid, and reductions in inconvenience, there would be more participation in utility and third-party DR programs. The market intervention in marketing and outreach accelerates the adoption of the technology, which can be measured by the difference between a baseline adoption rate in the business-as-usual case and the accelerated adoption rate due to greater customer awareness as they try the technology for themselves or observe others using the technology.

While the theories are straightforward, the empirical analysis presents a number of challenges. The first challenge is measuring the dynamic baseline, the progression of the market in terms of selection probabilities with no market intervention. The baseline for measuring market transformation effects can depend on many economic factors such as changes in the external business environment with respect to the level of economic activity and technical change. The baseline must also control for the rate of change in selection probabilities due to the naturally occurring diffusion process. As stated in the “California Evaluation Framework” document, “clearly if something is too hard to measure, too changeable to get a handle on, or too vague to define, the evaluation is in trouble….”[[22]](#footnote-22)

The second challenge is measuring the selection probabilities when the intervention is removed. Very little empirical analysis has been done of long-term sustainability of the change in probabilities of technologies in the choice set in the energy efficiency area, leading practitioners to state, “even the most rigorous methods for modeling long-term market effects can be regarded as producing highly uncertain results.”[[23]](#footnote-23)

The third challenge is causally relating the specific market intervention to the changes in the market. Perhaps the best we can do in this area is to theoretically relate the market intervention and the resulting market changes and decide whether the theory or alternate theories better explain the changes in the market. For example, Northwest Energy Efficiency Alliance program increased the market share of efficient windows from 15 percent to over 60 percent over a period of several years. Evidence that the program was the cause of the increase included window manufacturers crediting the program for the change and the fact that nowhere else in the country did this magnitude of increase occur in the sales of efficient windows. There were also no other utility incentives or promotions to account for the change.[[24]](#footnote-24)

The fourth challenge is to assess sustainability. To be a successful market transformation, it must permanently alter the choice set. For programs that lead to regulation changes that impact the choice set as with CFLs, this element is easy to assert. But for programs with no resulting mandates, as is the case in DR, the sustainability assessment is speculative. For example, the market transformation program in the Northwest for high efficiency manufactured homes increased the market share of high efficiency units to 94 percent. But 3 years after the program ended, the penetration level had dropped to a 54 percent market share.[[25]](#footnote-25)

The DR Potential Study assumes prices of DR technologies will decline by 10 percent by 2025 and the amount of demand reduction per customer will increase by 20 percent related to market transformation.[[26]](#footnote-26) SDG&E assumes this level of market transformation for all residential DR programs and C&I programs relying on automation technology for demand response in the qualitative benefit analysis.

1. **Utility non-energy benefits or costs.**

These benefits and costs consist of any indirect change in costs that an LSE or distribution utility experiences as a result of DR programs not included in DR budgets. SDG&E found no literature suggesting there any changes in the number of complaint calls or service requests to an LSE, increased billing costs of an LSE, any changes in customer perception or relationship to its LSE, or any changes in the number of LSE delinquent bills related to participants in utility or third-party DR programs. However, LSEs in the San Diego area do not make this type of data known to SDG&E.

As explained above, SDG&E does consider the short-term effect on market prices consistent with FERC Order 745. As long as the bid price of DR resources is above the net benefits test price, there is no compensation to the load-serving entity for energy not purchased at the retail rate. This qualitative benefit to the DR provider is a negative impact on the non-participating utility customers.

SDG&E has no data supporting any change in the number of complaint calls or service requests to the utility, any changes in customer perception or relationship to SDG&E (except the negative perception when the number of DR calls to reduce load are high), any differences in the number of utility delinquent bills or disconnections among DR participants, or increased billing costs other than the costs contained in the DR Application. SDG&E cost savings in marketing and administrative budgets of DR customer participation in Energy Efficiency programs is implicitly considered in the co-benefits of enabling technologies.

1. **Implementation**

All quantified qualitative benefit factors in this analysis are used in a sensitivity to the base results. SDG&E’s position is that ratepayer-funded DR should not consider non-market social costs as the utility customers are not society unless instructed to by the legislature, such as with the social cost of carbon in AB 197. Other non-energy benefits such as market transformation benefits, customer non-energy benefits, and customer co-benefits used in the DR Potential Study are speculative at best and supported by little analysis.

The sensitivity case is based on adding in 1) the social costs of air pollution, 2) one-third the renewable premium as considered in Energy Efficiency as part of the cost of carbon, and 3) reduced DR costs for programs using DR technology in consideration of the market transformation benefits found in the DR Potential 2025 medium case (10% reduction in cost of enabling technology with a 20% increase in MW reduction/customer). No other qualitative benefits or costs are considered quantitatively except the ones already included in the analysis – the GHG cost embedded in the energy price, the short-term market price suppression benefit embodied in FERC Order 745, and the inclusion of co-benefits of enabling technology costs.

1. The analysis of storage and its multiple uses, including the potential revenue stream from providing demand response, is complicated and has been addressed in the Commission storage proceeding (R. 10-12-007). [↑](#footnote-ref-1)
2. For residential customers, response to TOU rates is being considered in the Residential Rates OIR (R.12-06-013). More generally, see: Lawrence Berkeley National Laboratory, E3, and Nexant; 2015 California Demand Response Potential Study Charting California’s Demand Response Future, Final Report on Phase 2 Results; November 14, 2016 in R.13-09-011, Appendix G. [↑](#footnote-ref-2)
3. The types of DR to address new needs related to renewable generation include increased end-use consumption during periods of excess renewable generation, DR to provide flexible capacity for ramping needs created by solar generation, and DR to smooth intra-hour variability due to variable renewable generation. See the DR Potential Study, Phase 2 Report. [↑](#footnote-ref-3)
4. The Administrative Law Judge’s Ruling Requesting Comments on 2015 California Demand Response Potential Study Draft Report on Phase Two Results (Draft Report) and Noticing a March Workshop to Develop New Models of Demand Response (Ruling), issued December 15, 2016 in R.13-09-011. [↑](#footnote-ref-4)
5. See LBNL, page 6-2. [↑](#footnote-ref-5)
6. LBNL, Table 4, page 3-9. [↑](#footnote-ref-6)
7. The co-benefits analysis is based on the LBNL Study, pages 4-5 – 4-7. [↑](#footnote-ref-7)
8. If market prices are lower in peak periods relative to other periods due to a demand response program, market price volatility is lower by definition, all other things being equal. And assuming market prices in peak periods are related to potential shortages, lower market prices in peak periods are correlated with increased reliability. [↑](#footnote-ref-8)
9. Energy and Environmental Economics, “Methodology and Forecast of Long-Term Avoided Costs for the Evaluation of Energy Efficiency Programs,” October 25, 2004. [↑](#footnote-ref-9)
10. LBNL, page 6-2. [↑](#footnote-ref-10)
11. U.S. Department of Energy developed a study, “Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them,” February 2006, pages 26-29. [↑](#footnote-ref-11)
12. DOE, page 71. [↑](#footnote-ref-12)
13. DOE, page 71. [↑](#footnote-ref-13)
14. DOE, page 81. [↑](#footnote-ref-14)
15. This section is taken from the following James Bushnell, Benjamin Hobbs, and Frank A. Wolak, “When it comes to Demand Response, is FERC its Own Worst Enemy?” The Electricity Journal, November 2009. [↑](#footnote-ref-15)
16. Current avoided cost calculator, tab “Emissions” values for a low efficiency plant. The dollar values were provided by E3 for an EV cost effectiveness analysis. [↑](#footnote-ref-16)
17. AB 1937 [↑](#footnote-ref-17)
18. LBNL, page 6-2. [↑](#footnote-ref-18)
19. CAISO, *Senate Bill 350 Study, The Impacts of a Regional ISO-Operated Power Market on California,* volume VIII. [↑](#footnote-ref-19)
20. Blumstein, C., S. Goldstone, and L. Lutzenhiser, “From Technology Transfer to Market Transformation,” working paper. [↑](#footnote-ref-20)
21. TecMarket Works, *California Evaluation Framework,* Joint Study mandated by CPUC, 2004. [↑](#footnote-ref-21)
22. TecMarket Works. [↑](#footnote-ref-22)
23. TecMarket Works. [↑](#footnote-ref-23)
24. TecMarket Works. [↑](#footnote-ref-24)
25. York, D., “A Discussion and Critique of Market Transformation, Energy Center of Wisconsin,” 1999. [↑](#footnote-ref-25)
26. LBNL, page 3-9. [↑](#footnote-ref-26)