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CONSERVATION AND DEMAND-SIDE MANAGEMENT

Leading the pack in energy efficiency and renewable energy is the standard for California. Rigorous environmental regulations and evolving energy policy places the state at the forefront of environmental stewardship.

Energy agencies within the state adopted an Energy Action Plan (EAP) that has been a catalyst for numerous energy-related policies. In 2003, the EAP established a "loading order" for the acquisition of new resources that prioritizes energy efficiency. Since that time, a number of state-mandated regulations have been enacted to support this policy, such as Senate Bill (SB) 1037. SB 1037 requires public and private gas and electric utilities to first acquire all available energy efficiency and demand reduction resources that are cost effective, reliable and feasible before conventional generation or other resources.

IID is committed to investing in all available energy efficiency and demand reduction as a supply resource. The IID offers a variety of conservation and DSM programs intended, in part, to alleviate electric generation requirements and avoid expensive peak purchases of power on the market. Conservation programs are designed to reduce the total amount of energy used while DSM programs are designed to shift energy use from high cost periods to low cost periods and reduce the cost of supplying customers.

New legislation, emerging technologies and evolving customer preferences are defining IID's energy efficiency and demand-side management programs.

Exhibit 1: Conservation and Daily Load

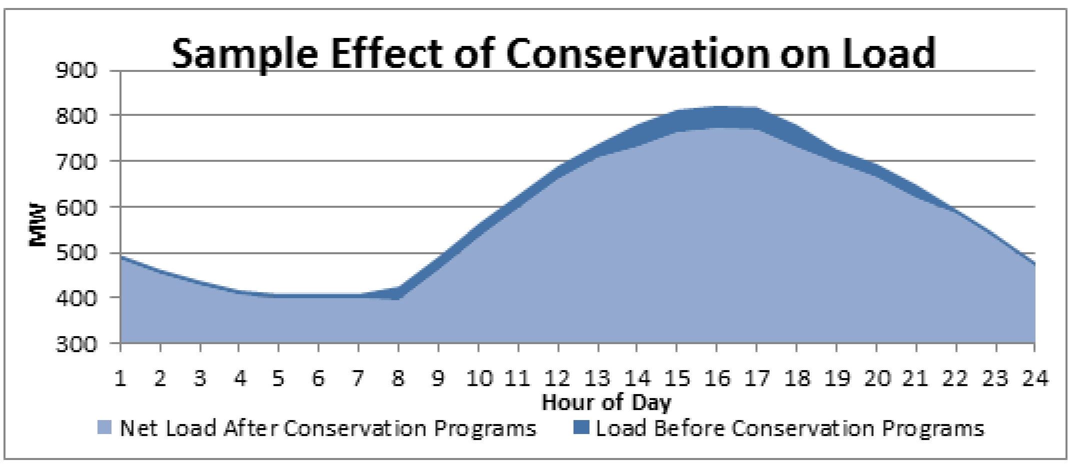
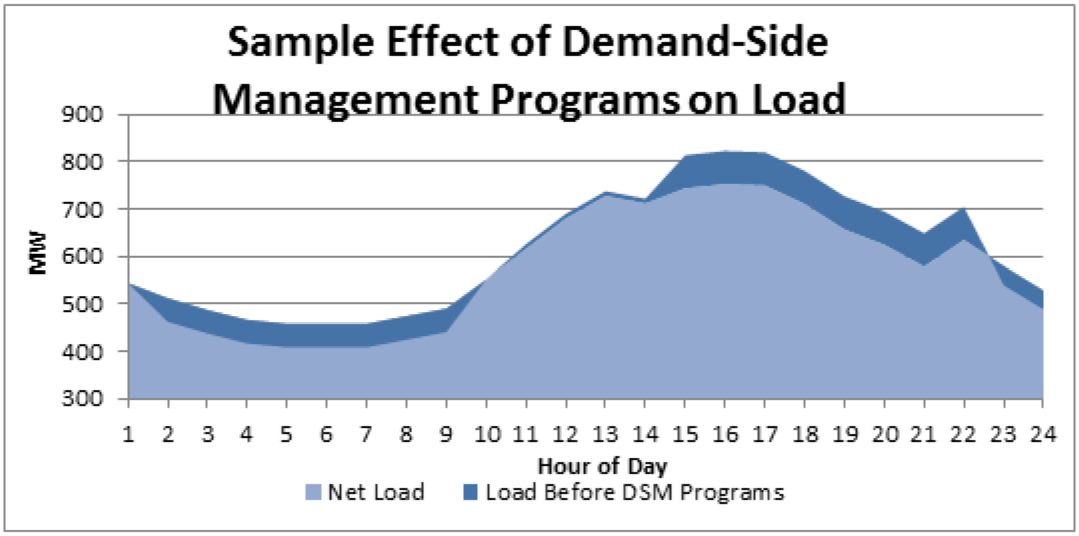


Exhibit 2: DSM and Daily Load



Currently, most programs within the IID's portfolio are conservation programs with the goal of reducing the customer's consumption and cost of energy. However, future programs may be designed to shift customer on-peak use to off-peak hours.

EVALUATION OF PROGRAMS

Conservation and DSM programs can be evaluated in a number of ways. Prior to implementation, and periodically throughout an existing program, cost-effectiveness tests are applied to determine if the investments are comparable to, or better than, the range of other available resource options. There are five industry-standard cost-effectiveness tests used to compare the benefits of energy efficiency with the costs to invest in implementation of the efficiency measures.

As a general rule, California utilities deem a total resource cost of "1" or greater as an indicator of a cost-effective program. However, comprehensive evaluation using a combination of the various tests provides for more definitive assessment of impacts and effects the program will have. Benefits and costs used to evaluate cost effectiveness of energy efficiency and DSM programs and services are identified in the exhibit below. The following is a summary of the five approaches to evaluation:

1. Participant Cost Test (PCT) – This approach provides an assessment of the costs and benefits from the perspective of the customer installing the measure(s). PCT of 1 or above indicates that the customer will see net savings over the expected useful life of the measure.

2. Utility/Program Administrator Cost Test (PAC) – Opposite of the PCT, this approach assesses the costs and benefits from the perspective of the utility implementing a program. A positive PAC result indicates that the costs to save energy are less than the utility's cost to deliver the same power. Additionally, the customer's average bill should reduce once the measures are implemented.

3. Ratepayer Impact Measure Test (RIM) – This test evaluates the potential impact the program may have on the overall electric rates. As RIM results tend to be negative, many utilities, including IID, emphasize the results of PAC tests over RIM to balance the distribution of rate impacts.

4. Total Resource Cost Test (TRC) – As the primary evaluation approach, the TRC illustrates the total benefits and costs to both participating and nonparticipating customers. This test shows the net benefits of the program as a whole without regard as to who (utility or customer) pays the cost of the measure(s) installed.

5. Societal Cost Test (SCT) – The SCT includes both costs and benefits that are not captured monetarily in the TRC such as greenhouse gas reductions or other environmental benefits.

Exhibit 3: Cost/Benefits of Conservation and DSM

COMPONENT	PCT	PACT	RIM	TRC	SCT
Energy and capacity-related avoided costs		Benefit	Benefit	Benefit	Benefit
Additional resource savings				Benefit	Benefit
Non-monetized benefits					Benefit
Incremental equipment and installation costs	Cost			Cost	
Program overhead costs		Cost	Cost	Cost	Cost
Incentive payments	Benefit	Cost	Cost		
Bill savings	Benefit		Cost		

Source: California Public Utilities Commission (CPUC). (2001). California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

California Assembly Bill 2021 (Levine) that was signed into law in 2006 expanded upon several existing energy efficiency policies, including SB 1037. Among other mandates, it requires all publicly-owned utilities to perform third-party measurement and verification studies of their conservation and DSM programs. These independent program evaluations, commonly referred to as EM&V, are performed by third parties to provide an unbiased assessment of programs as well as measurement and verification of energy, demand and peak savings generated through the portfolio. IID's EM&V plan consists of evaluation of its programs on a bi-annual basis, covering programs for a two-year cycle. Not all programs will be evaluated in each evaluation cycle. Programs that generate the most energy savings will be routinely assessed while others will be included on an as-needed basis.

Evaluation results allow the IID to determine if its programs are effectively reducing energy use by its residential and commercial customers. Using information from this report, local demographics and the IID's overall strategic goals, existing programs are assessed to determine if more cost-effective programs should be expanded at the expense of some of the less effective programs. Programs that only benefit participating customers may be scaled back or eliminated unless they have significant environmental or other societal benefits to the IID that cannot be quantified for customers. At times, the IID, at its sole discretion, may invest in programs or projects with lower TRC values if they align with specific strategic or policy-driven goals.

Energy Efficiency Portfolio Target

Assembly Bill (AB) 2021 also requires each publicly owned utility to identify all potentially achievable cost effective electricity efficiency savings and shall establish annual targets for energy efficiency savings and demand reduction for the next 10-year period. IID has joined together with California Municipal Utilities Association (CMUA) in partnership with Northern California Power Agency (NCPA) and the Southern California Public Power Authority (SCPPA) to collaborate on the development of individual utility energy efficiency and demand-reduction targets. The targets are based on a methodology developed by the Rocky Mountain Institute (RMI), an independent organization with well-accepted energy efficiency expertise in the industry. The RMI model is designed to estimate the technical (full extent of energy efficiency potential without regard to practicality or costs), cost effective and feasible energy efficiency potential.

Consistent with provisions of AB 2021, the targets adopted in 2011 by IID's Board of Directors were re-evaluated in 2014 and new figures were adopted the exhibit below reflects IID's current MWh targets by program year through 2023.

Assembly Bill 2227 (Bradford, 2012) modified the evaluation period for energy efficiency targets from every third year to every forth for the subsequent years.

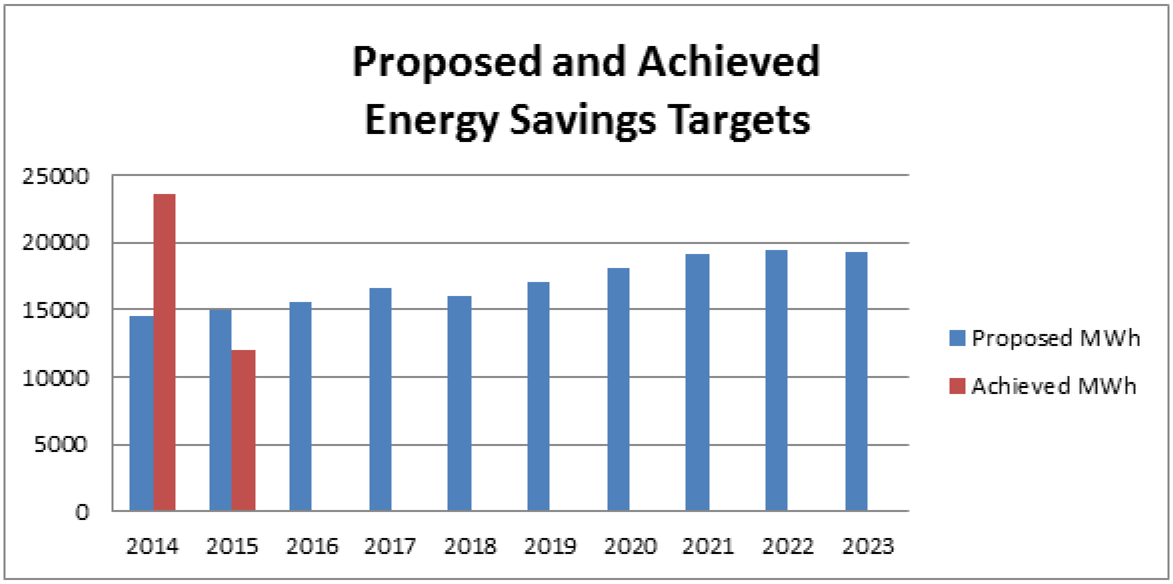
Senate Bill 350 (De León) enacted the "Clean Energy and Pollution Reduction Act of 2015" which established targets to increase retail sales of renewable electricity to 50 percent and double the energy efficiency savings in electricity and natural gas by end uses by 2030. IID is evaluating emerging technologies and innovative program concepts to develop a multi-year running program portfolio to meet the energy efficiency targets set forth by this legislation.

In 2015, Assembly Bill 802 (Williams) was also passed into law, replacing the existing AB 1103. AB 802 sets the framework for a new energy use disclosure program, which will allow owners and operators of commercial and multifamily buildings containing 50,000 square feet and more to better understand their energy consumption through standardized energy use metrics of 12 months of historical whole-building utility data. The whole-building energy use approach depicts how the building is performing as an entire system, facilitating building owners to make more effective decisions on energy efficiency upgrades. As energy targets are reevaluated as per AB 2227, legislation, Title 24 requirements, rooftop solar and IID's public program budget will be considerable factors in the adoption of the new figures.

On August 3, 2015, the Environmental Program Agency (EPA), under Section 111(d) of the Clean Air Act, finalized the Clean Power Plan (CPP), a rule that sets performance rates and individual state targets for carbon dioxide emissions from existing power plants. California's 2030 goal is 828 pounds per net megawatt hour, which is lower than most states as California's state regulations are already amongst the most stringent in the nation. The CPP was met with several legal challenges and on February 9, 2016, the Supreme Court issued a stay on the enforcement of the plan halting its implementation pending the resolution of the challenges. IID will continue to prepare for potential compliance should the legislation be upheld.

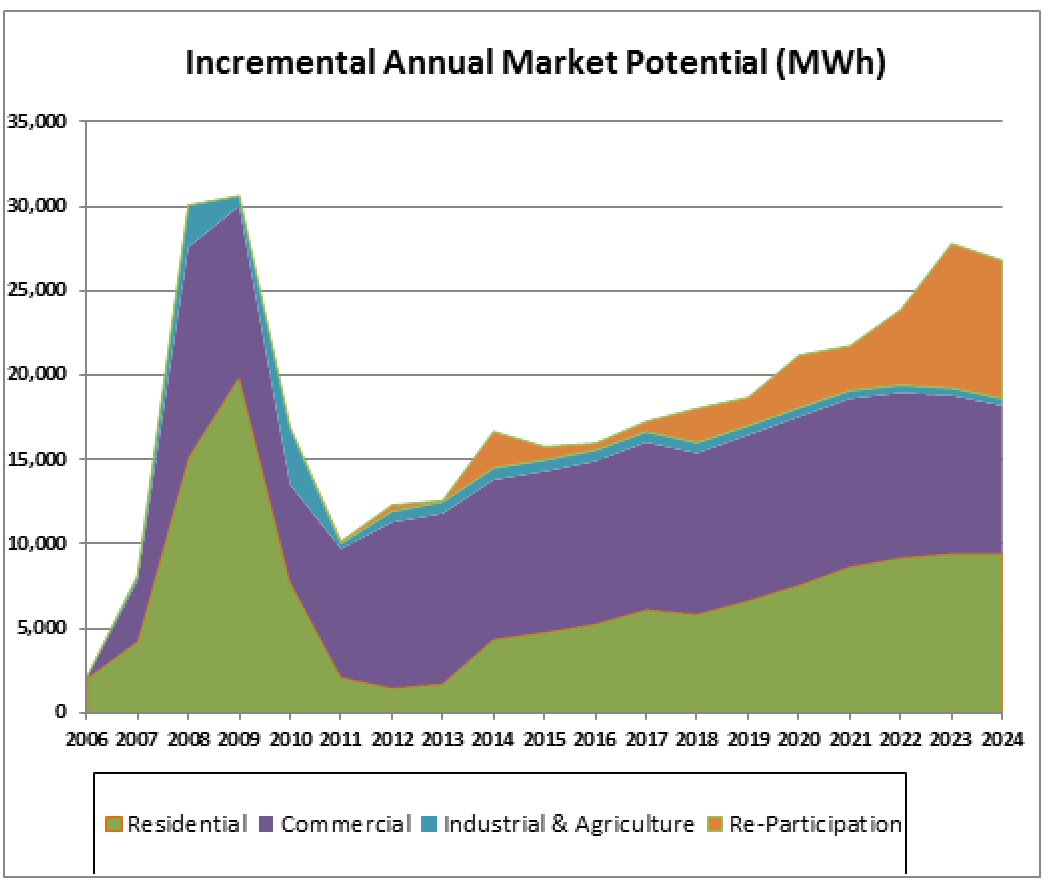
Through the IID's energy efficiency efforts, from 2009 through 2015, has reported saving over 116,000 megawatt hours saved.

Exhibit 4: Proposed and Achieved Energy Savings Targets



These targets consist of energy savings and demand-reduction potential in existing buildings and new construction for residential, commercial and industrial sectors. Figures are reported to the state and published annually in the Energy Efficiency in California's Public Power Sector report.

Exhibit 5: Incremental Annual Market Potential for Energy Savings



Source: 2014 IID Energy Efficiency Resource Assessment Model – Electricity & Natural Gas

Effects of Existing Programs

To support the state's long-term energy goals, a number of mandates have been implemented to not only encourage but to prioritize investments in all available energy efficiency and demand-reduction resources that are cost effective, reliable and feasible. As such, California utilities are to first meet load with these investments prior to procurement of other resources. On an annual basis, IID and other utilities report investment funding, cost-effectiveness methodologies and independent evaluations to the board, the state and our customers.

From 2013 through 2015, conservation programs implemented by the IID saved participating customers approximately 53,354.15 MWh in energy savings 41.36 in peak kW savings. The most successful programs, in terms of energy saved, have been the Custom Energy Solutions Program (CESP) and Quality A/C Maintenance. Overall reported savings were a result of various measures within the residential and commercial sectors.

Exhibit 6: Summary of 2013-2015 Energy Savings

Program Sector	Category	Units Installed	Net Demand Savings (kW)	Net Peak kW Savings	Gross Annual kWh Savings	Net Annual kWh Savings	Net Lifecycle kWh savings	Utility Incentives Cost ($)	Total Utility Cost ($)
HVAC	**Res**	1,983,704	5,544	17,973	22,104,755	18,371,065	249,614,401	$12,147,689.17	$14,487,944.05
Lighting	**Res**	14,399	338	273	548,725	508,763	2,884,242	$153,917.83	$347,672.94
Pool Pump	**Res**	907	23	205	1,135,953	988,279	9,882,791	$134,504.00	$248,875.37
Refrigeration	**Res**	2,283	12	41	885,627	514,142	4,513,110	$213,160.28	$260,864.52
Water Heating	**Res**	7			532	532	7,980	$316.00	$990.98
Comprehensive	**Res**	1,988	50	110	677,000	560,528	1,983,925	$408,593.81	$543,936.11
HVAC	**Non-Res**	34,807	4,091	5,206	16,391,699	14,376,254	180,746,562	$6,095,821.68	$7,122,502.00
Lighting	**Non-Res**	66,386	2,206	16,902	16,577,990	14,639,975	205,031,421	$4,243,442.71	$5,560,393.90
Refrigeration	**Non-Res**	3,557	265	257	2,593,138	2,369,900	19,564,138	$357,253.54	$450,199.50
Process	**Non-Res**	464	380	370	1,106,579	977,526	9,049,438	$146,443.60	$278,385.36
Comprehensive	**Non-Res**	36		21	58,980	47,184	141,552	$22,337.92	$36,082.76
SubTotal		**2,108,538**	**12,909**	**41,358**	**62,080,978**	**53,354,149**	**683,419,561**	**$23,923,480.54**	**$29,337,847.49**

Description of Existing Programs

The 2016 program portfolio is structured to allow IID to meet their annual target of 15,563 MWh. An overview of each program is provided below.

Residential Programs

Residential Energy Audits - This program allows residential customers to quantify energy consumption and to determine measures that can be applied to make the customer's home more energy efficient.

Energy Rewards Rebate Program - This program offers residential prescriptive rebates for qualified energy efficient measures such as air conditioners, ENERGY STAR® refrigerators, windows, attic insulation and pool pumps. New to the 2016 program is the ENERGY STAR® clothes washer incentive.

Refrigerator Recycling - The IID offers a $50 incentive and free refrigerator pickup with proper recycling services to our customers. This program targets older, less efficient units and those kept in basements or garages.

Quality AC Tune-Up - This program provides maintenance services designed to improve the operating efficiency of existing central air conditioners or heat pumps.

Payment Assistance - The IID offers income-qualified assistance programs designed to help customers meet their energy needs. Rate discounts are offered to income-qualified customers and a special rate is offered for those using critical medical equipment. A financial assistance program is also offered to customers facing financial crisis that are at risk of disconnection for nonpayment.

Commercial Programs

Custom Energy Solutions Program (CESP) - CESP offers financial incentives to commercial customers intended to offset the cost to purchase and install qualifying energy efficiency measures. The measures must retrofit, replace or upgrade old equipment with new, energy-efficient technologies that exceed the applicable Title 24 energy efficiency requirements.

New Construction Energy Efficiency Program (NCEEP) - NCEEP is a non-residential new construction and renovation energy efficiency program that combines an integrated design process with financial incentives for energy-saving design at least 10 percent above the current Title 24 requirements.

Commercial Energy Audits - This program allows commercial customers to meet with an energy specialist to evaluate their business' current energy use and identify ways in which to reduce their consumption, making their facility more energy efficient.

Energy Rewards Rebate Program - IID offers nonresidential customers prescriptive rebates for qualified energy-efficient measures. Measures must retrofit, replace or upgrade old equipment with new, energy-efficient technologies that meet and exceed the Title 24 standards. Qualifying product categories include programmable thermostats, HVAC equipment and motors.

The IID is also looking to new and emerging technologies such as home energy management systems and smart thermostats that offer customers new opportunities to manage their energy use. As these devices become more economic and integrated with each other, customer systems will offer automatic responses to changing utility price signals in real time, optimizing the operation of key appliances and energy systems to manage peak demand and reduce costs.

RATES

The IID also offers interruptible and high-voltage rates for its large commercial and industrial customers.

Key Customer Demand Response Program (Interruptible Load Program) - This program was developed in 2010 with a target participation of 25MW within three years. Program guidelines require enrolled large commercial and individual customers with on-site back up generation to curtail a minimum of 500kW upon timed notice by IID. Failure to curtail contracted reductions will result in a financial penalty. This generation can be used to reduce load during times of system stress either due to transmission or generation curtailments or if load exceeds forecasted demand.

High Voltage Rate Discount Program - Under this program, customers take electric services at 34.5 kilovolts or above at a single point of interconnection. The customer maintains all necessary step-down transformation and facilities beyond the transformer, which IID would normally own. In return, IID will provide a discount on the maximum demand energy charge and energy cost adjustment charge. The reduced electric rate offsets some of the customer's costs for the facilities, maintenance and necessary substation equipment.

RENEWABLE-ENERGY PROGRAMS

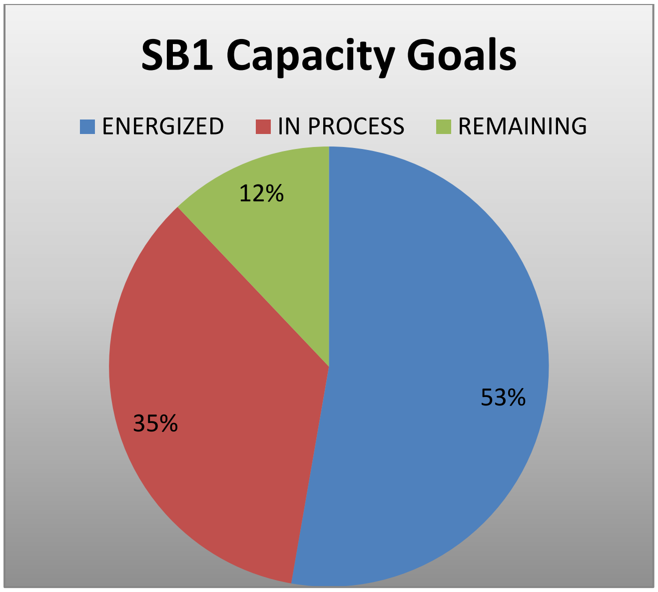
To help customers fully benefit from investments in various renewable options, the IID offers a number of retail renewable programs.

Solar Solutions Program

Electric corporations and publicly-owned utilities, including IID, are mandated by state law, specifically Senate Bill 1, to offer a solar initiate program for the purpose of investing in and encouraging the increased installation of residential and commercial energy systems. Per the legislation this program is scheduled to sunset in 2016, as such this is the final year. The IID will offer monetary incentives through its Solar Solutions Program for eligible systems up to the first 15kW (residential), 300kW (commercial) and 400kW (government/nonprofit) CEC-AC of generating capacity electric load.

IID's overall program budget totals $40,219,809 over the course of the program. IID's expenditure level was based on IID's percentage of the total statewide load served by all local publicly-owned electric utilities or 5.13 percent. The program goal allocated to the IID totals 44MW. Throughout the course of the program the incentive rate was reduced on a scaling basis to allow additional customers to benefit from the rebate. The program continued to self-subscribe within days of opening each year.

Exhibit 7: SB1 Capacity Goal



There are two acceptable performance-based approaches to incentive distribution: the expected performance-based incentive (EPBI) approach offered for projects less than 30kW and the performance-based incentive (PBI) approach for projects 30kW and above. The EPBI approach pays an upfront incentive while PBI is based on the solar energy system's actual production (kWh) over a five-year period. The PBI incentive payment is calculated by multiplying the incentive rate ($/kWh) by the measured kWh output.

Due to PBI, IID will continue to pay projects through 2021.

Exhibit 8: SB1 Program Funding

Total Program Funding	Total Incentives Paid (through 2015)	Funds Remaining	Total Incentives Reserved (Include 2016 reservations)	MW Goal	Remaining MW to Goal
$40,219,809	$20,147,338.50	$6,174,366.36	$34,045,442.64	44 MW	5.2 MW

Net Energy Metering

Net Energy Metering (NEM) is a program designed to benefit IID customers who generate their own electricity using solar, wind, biogas, fuel cell or a hybrid of these technologies. The program includes generating facilities up to 1MW and is offered on a first-come, first-served basis. IID's NEM program capacity is 50.2MW, five percent of IID's peak demand.

An installed bidirectional meter records the amount of energy (in kWh) delivered by the IID to the customer's premise, which is called net consumption. It also records the amount of energy (in kWh) generated by the customer's generating system, which was not consumed by the premise and thus returned to the IID's electrical grid. This is referred to as net generation. The net difference between these two amounts is what IID uses to create the participating customer's monthly bills.

Consistent with AB 920, the IID established a rate to purchase surplus electricity. At the end of a 12-month period, customers who are net generators will be compensated for surplus energy returned to the grid at the rate stated in the current net metering rate schedule. At the end of the 12-month period, customers that are net consumers, but in any given month within the 12-month period are a net generator, that monthly surplus energy will be tallied and credited to the customer at IID's current retail rate.

Although IID met its 50.2MW cap in the first quarter in 2016, it extended the program by an estimated 9.6MW to allow for customers that were in the process of submitting their applications an opportunity to participate. For the remaining customers that desire to generate all or a portion of their energy consumption, IID has developed the Net Billing successor program to continue to facilitate customer interconnection projects to IID's grid.

Exhibit 9: Net Energy Metering Program Installation Summary

Category Type	Total Systems Installed	Installed Capacity (kW)	Total Generation (kWh/yr)
Residential	3,662	22,018	47,659,996
Commercial	177	27,566	69,064,895
Government	8	718.21	1,551,133
Total	3,847	50,302	118,276,024

Net Billing Program

The Net Billing Program, successor to the Net Metering Program, is designed to benefit customers who generate their own electricity using solar or wind. The program paves the way for new solar development while at the same time reducing cross-customer subsidization between those with and without solar. Net consumption is billed to customers on each regular billing frequency and not aggregated to a 12-month period. Any net generation is compensated on each billing cycle at the applicable Distributive Self-Generation Service Rate. This is a variable rate and based on IID's lowest solar contract cost as which IID procures solar generation. The rate will be modified as deemed necessary by IID's board of directors.

Exhibit 10: Net Energy Metering Program Installation Summary

Category Type	Total Systems Installed	Installed Capacity (kW)	Total Generation (kWh/yr)
Residential	73	376	797,412
Commercial	0	-	-
Government	0	-	-
Total	73	376	797,412

Feed-In Tariff (FIT)

SB 32, enacted in 2009, required the IID to implement a Feed-in-Tariff (FIT). The FIT program was adopted and approved by the IID Board of Director during the second quarter of 2013. In anticipation of the adoption of the program, IID accepted applications for the FIT program on a first-come, first served basis, which has been fully subscribed since January 16, 2013. The tariff provides a simple mechanism for small renewable generators (less than 3MW) to sell power to the utility at predefined terms and conditions, without engaging in contract negotiations.

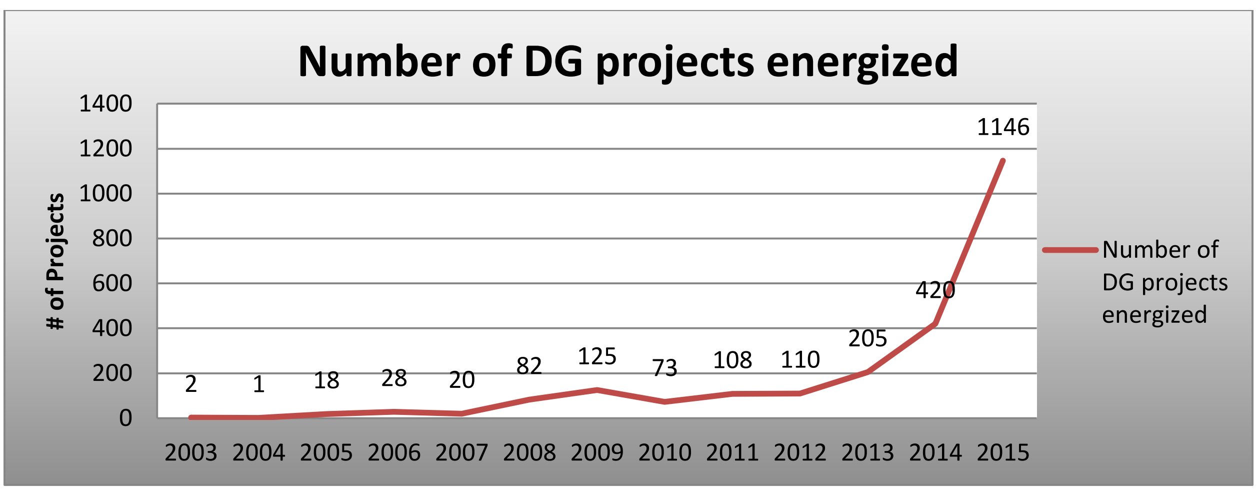
Senate Bill (SB) 1332 established Feed-in Tariff program caps determined by the ratio of the utility's 2011 peak demand to the 2011 statewide peak demand. For IID, this cap is estimated to be approximately 13MW.

Eligibility criteria for IID's FIT consists of the following:

1) The project must be located within the IID service territory;
2) The project must be between 1kW and 3MW;
3) The project must be located and interconnected in a manner that optimizes deliverables of generation to load centers; and
4) The project must install eligible renewable generation.

Through the tariff, IID will purchase all generation from the facility and all Renewable-Energy Credits (REC) will belong to IID. Generating Facilities participating in the Feed-in Tariff program may not offset load at the site/facility nor are they eligible for any other IID for renewable technologies program (i.e., net metering rate, virtual net metering rate, etc.). Feed-in Tariff program participants also may not receive rebates from IID's SB1 PV/Solar Solutions Program.

Exhibit 11: Number of Distributed Generation Energized per year through 2015



Energy Storage Systems

As renewable-energy generation tends to be variable, intermittent and off peak, energy storage systems may optimize the use of significant additional generation that will be entering the grid on an accelerated basis as a result of California's energy goals. The state has declared that expanding the use of energy storage systems can reduce costs to ratepayers, reduce emissions from fossil fuel generation and enable and accelerate the implementation of more renewable generation and its integration in California's electrical system.

On September 29, 2010, the California Legislature enacted Assembly Bill (AB) 2514 directing the California Public Utility Commission and governing board of a local publicly-owned electric utility to initiate proceedings prior to March 1, 2012, to determine energy storage procurement targets, if any. This legislation, considered the foremost statute relating to utility procurement of energy storage systems, asserts a number of findings regarding the value of energy storage and barriers that hinder timely implementation.

As part of the proceeding, the board of directors considered a variety of possible policies to encourage the cost-effective deployment of energy storage systems, including refinement of existing procurement methods to properly value energy storage systems. As required AB 2514 in 2014 the IID Board of Directors, as the governing board of IID, adopted an energy storage system procurement target of "0" due to the time and effort necessary to successfully complete planning and implementation of the reliability projects. The target is to be reevaluated no later than October 2017.

Since that time, the IID has engaged in significant planning of physical improvements to help insure reliability pertaining to its operation of the bulb electric system. These high priority improvements consist of, but are not limited to, IID's strategic transmission expansion plan and battery storage.

Battery Energy Storage System (BESS)

In November of 2015, the IID held a groundbreaking ceremony to mark the start of construction of their new 30MW, 20MWh lithium-ion battery storage system. The battery will increase reliability across the IID grid by providing the ability to balance power and integrate solar while providing spinning reserve and "black start" power restoration capabilities. The project is one of the largest of its kind in the western United States. It will consist of associated controllers, a substation and a 92kV interconnection. The project will use environmentally safe lithium-ion batteries. Some of the benefits of the Project are as follows:

- Reliability – This project adds reliability to the IID grid, the district can use the battery system to "black start" units at the El Centro Generation Station, one of IID's main internal sources of generation.

- Environmental – The battery storage system will smooth power supplies and acts as a spinning reserve, assignments that typically require expensive fossil fuel generation.

- Economic – Reduction in IID operating costs in the first year and throughout the lifetime of the project which provides significant cost savings to rate payers.

The BESS project was completed in mid-2016.

Ice Bear Thermal Energy Storage Program (Ice Bear)

Currently, there are five Ice Energy Ice Bear Thermal Energy Storage (TES) units installed at the IID's La Quinta office located in Coachella Valley. The units are designed to reduce air-conditioning loads for small commercial and large residential air-conditioning systems. The units create ice during off-peak hours and use the ice during on-peak hours for air conditioning, allowing the air conditioner to turn off the compressor system.

TES units typically supplement and, in some cases, can replace A/C systems for large customers including hospitals and large office buildings. In an area as warm as the IID's service territory, TES systems tend to be larger than in more temperate climates as sufficient ice must be made during the off-peak hours to keep the compressors from having to be operated during the super-peak periods. Because TES systems must be oversized, the additional cost tends to provide the greatest benefits for customers that have high on-peak A/C load.

Moreover, the benefits of the TES system are dependent upon how many hours the unit must run to create ice necessary for on-peak cooling. In cooler parts of the country, the units can create enough ice off peak to allow the compressors to remain off during the eight on-peak hours. In the IID's two major load zones, El Centro and La Quinta, temperatures may be so high that the TES system must make ice for up to 20 hours, resulting in four hours daily load reduction.

These units were installed to determine how TES units would perform during seasonal extreme temperatures. Based on historical pricing, the IID would like to see sufficient load shifting to lower energy cost hours for such a project to be deemed cost effective.

Other Investments

From time to time, the IID invests in pilot projects to assess the impact, benefits and performance of new and emerging technologies or to test concepts for suitability. These pilots may result in implementation of full-scale programs if it meets cost effectiveness, qualifications or policy-driven goals. Examples of these investments may include:

- Development of emerging technologies for the market via a small-scale program designed to demonstrate the costs and benefits to decision makers and increase market penetration in the technology market.
- New combinations of existing and new technologies, control systems or software to dramatically increase the anticipated savings from each component of the system due to synergies between components, which may be implemented elsewhere.

IID, in its sole and absolute discretion, determines if funds shall be made available and what technologies and/or approach, if any, will be used to pilot a program. Projects that are typically deemed ineligible for funds consist of unproven new technology, tool development, research and development (R&D) or completion of product development as well as demonstration projects, R&D prototypes, and limited production technologies that cannot support an effective regional energy efficiency program.

The IID welcomes the opportunity to collaborate with other agencies on energy efficiency, renewable or other sustainable projects and programs. Collaborative efforts allow the agencies to share resources that benefit both the utility and our ratepayers while providing detailed information that helps determine whether the utility and its ratepayers will benefit from large scale investments.

E-Green Program

To present robust and accurate information about community based e-green solar, the team examined IID's current distributed generation programs, as well as other utilities' mechanisms for launching customer choice programs.

In its analysis of a community based "e-Green" solar program, the team defined business objectives as:

- Increase public understanding of solar energy and its role in IID's renewable transformation

- Create an attractive program in which all customer classes can enroll while being viable, economic and sustainable for IID
- Assure simplicity for customers and IID (administrator) alike
- Alleviate the potential load and revenue losses to the utility
- Integrates easily into IID's billing system (SAP)
- Apply Renewable Energy Credits (RECs) to Renewables Portfolio Standard (RPS)
- Reduce risk to IID and its customers by structuring program funding by participants

Customer benefits or the reasons customers choose to participate include:

- Leverages economies of scale
- Offers lower cost of electricity and stable rates No up-front costs, drop-out penalties or system maintenance
- No hassle with contractors or red tape
- Available to all customers, except existing Net Energy Metering (NEM) and Virtual Net Metering (VNM) customers
- Increases customer access to solar

And, there are IID benefits, as well:

- Gives customers a choice
- Increases proactive customer engagement and loyalty
- Can be strategically sited
- Maximizes production
- Optimal distribution grid benefit and control
- Apply RECs to RPS
- Provide alternative for low-income customers (reduce use of Public Benefits Charge funding)

While identification of the benefits seemed intuitive for the team, the operational and financial analysis proved to be more complex. Resource Planning conducted a comparison of net operational cost impacts on various potential "e-Green" solar projects. This comparison is based on numerous production cost model simulations that compare how adding a resource will affect daily dispatch operations over a 20-year period. These studies include integration cost such as, ancillary services, loss of flexibility, ramping needs, operating reserves, etc.

The first operational study included multiple new facilities: 5 MW, 10 MW, 20 MW, 20 MW (phased in) and existing Feed-In Tariff (FIT) 2 MW (a breakdown of FIT prices can be shown in Appendix B) with contract prices varying from $40-$70/MWh (no escalation). The study concluded, using the existing FIT projects was the least expensive operational costs since these projects are already part of IID's portfolio. Any current IID solar project would yield the same results. The integration of a new facility would cause risks of ancillary service impacts, larger amounts of excess generation, slightly higher system costs, and risk of customer participation (which could cause a cross-customer class cost subsidization).

Based on the first study, management provided the team with a 20 MW project with a $50/MWh contract price with a buyout option in year 7. The team evaluated four buyout scenarios: buyout at a Fair Market Value of $100, $50, $30, and $15 million. The study concluded the buyout option would need to be in the range of $15-$20 million, but the risks of ancillary service impacts, larger amounts of excess generation, slightly higher system costs, and risk of customer participation (which could cause a cross-customer class cost subsidization) would still exist.

The third operational study helped mitigate the excess generation by the applying term sales. Term sales are sold at forecasted annual market prices at a cost lower than a purchase price which are based on historical sale data. Two sale volumes were analyzed: 20 MW and 50 MW, along with different sale periods: off-peak hours and all hours of the day (24 hours, 7 days), with contract prices ranging from \$30-\$50/MWh. During this time, the team was provided legal opinion regarding the use of Senate Bill (SB) 1 funds (Appendix E), these funds were applied to the FIT projects. The study concluded a 20 MW phased in project with 20 MW of off peak term sales was the least expensive, in terms of operational cost. The excess generation that comes with a new facility is sold back to the market, therefore recovering some of the costs of integrating the new resource to the IID supply stack. The operation cost savings by utilizing term sales for the new 20 MW facility would be \$10,006,000 (NPV) over a 20-year period. Please note: term sales would still cause risk and IID's risk policy would have to be modified and approved. By adding a new 20 MW facility, it would create a cross-customer class cost subsidization if IID does not fully subscribe the 20 MW.

At the request of management, the team evaluated only the 20 MW new facility at \$30/MWh with additional scenarios: high market price forecasts, economic sales, 3.5%, 6%, 11% spin requirements and shutting down one unit in the winter and summer. These scenarios would mitigate the ancillary services impact and excess generation. The study concluded that all scenarios yielded operational savings for IID, but the greatest savings came from economic sales. The last study conducted was built off the previous study and combined 3.5% spin requirement, economic sales and shutting down one unit in winter and summer. This scenario would yield the greatest savings of \$344,058,000 over a 20-year period (NPV). Please note: economic sales, reducing spinning reserves and shutting down one unit would cause risk and IID's risk policy would have to be modified and approved. By adding a new 20 MW facility, it would create a cross-customer class cost subsidization if IID does not fully subscribe the 20 MW.

A high level of the multiple studies conducted are shown in the illustration below, the full detail with analysis can be found in Section 5.3.

Exhibit 12: History of operational studies

<u>Recommendation for Community based "e-Green" Solar Program:</u>

The team recommends utilizing the SDSU Community Solar project (7 MW) from IID's current portfolio, this project was originally proposed and built for an IID Community Solar program. The FIT projects originally proposed could utilize SB 1 and PBC funds which were approved my IID's Legal section (Appendix E), but Finance section does not agree in applying SB 1 and PBC funds that come from rate revenues. The original operational cost NPV over a 20-year period would remain the same at $4,057,802,000 – whether using the SDSU project, FIT project or any other project in the current portfolio. The scenarios (economic sales, term sales, reduce spinning reserves and shutting down one unit) were theoretical and were used to help mitigate or control the risks of implementing a new facility. If IID were to implement any of those changes, policies and procedures would have to be modified and approved. Additionally, there would be operational savings of those scenarios in IID's current portfolio, without implementing a new facility. By utilizing a current project, this would eliminate the cross-customer class cost subsidization because all customers are paying these costs through the Energy Cost Adjustment (ECA) rate.

If management would like to implement a new facility (not currently in IID's portfolio), the risks are identified below with potential solutions. These solutions will change IID's operating procedures and must be modified and approved prior to implementing. The risk of cross-customer class cost subsidization will still be present when adding a new facility.

Alternatives:

An alternative would be to implement a larger new facility of 20 MW. In previous production cost modeling studies, risks associated with implementing a new 20 MW facility were identified and the final operational study was conducted to mitigate ancillary services impact and excess generation. The table below shows high level issues with potential solutions; based on management decision, only potential solutions highlighted in red were studied (ancillary services and excess generation impact). When the team studied economic sales, reducing spinning reserves, and shutting down a unit, these impacts helped mitigate ancillary service impacts and excess generation. Therefore, the studies concluded the combination of the three scenarios would have the greatest operation cost saving for a NPV 20-year period of $344,058,000. Please note: these scenarios have not been approved by departments and/or management and are theoretical for the case of the study. IID will have to modify various business activities to ensure economic value of the "e-Green" Solar program and to mitigate or control risks.

Exhibit 13: Potential Risks

Potential Solutions to Cost Impacts of Adding 20 MW	
Issue	**Solution**
Ancillary Service Impact	Apply battery settings to address this issue;
	Explore the purchase of ancillary services from neighboring markets;
	Explore new quick responding generation additions
Excess Generation	Explore unit economic cycling; Explore seasonal unit shutdown alternatives;
	Term sales or economic dispatch sales
Slightly Higher System Costs	RFP process can reduce contract costs through greater negotiating leverage
Risk of Customer Participation	Require developer to commit to assisting IID with Marketing Campaign

The final two operational studies reviewed a new 20 MW facility at $30/MWh project coming online mid-2018, with taking into consideration various system scenarios being implemented. The studied scenarios were evaluated based on mitigating ancillary service impacts and excess generation. Consequently, when we combine all system changes previously tested through a coordinated effort, then value can be added. Please note: the system changes (economic sales, reduce spinning reserves and shutting down a unit) would also add value in the case that does not add 20 MW new facility (IID's current portfolio).

Exhibit 14: "e-Green" Solar Operational Impact Study Scenarios

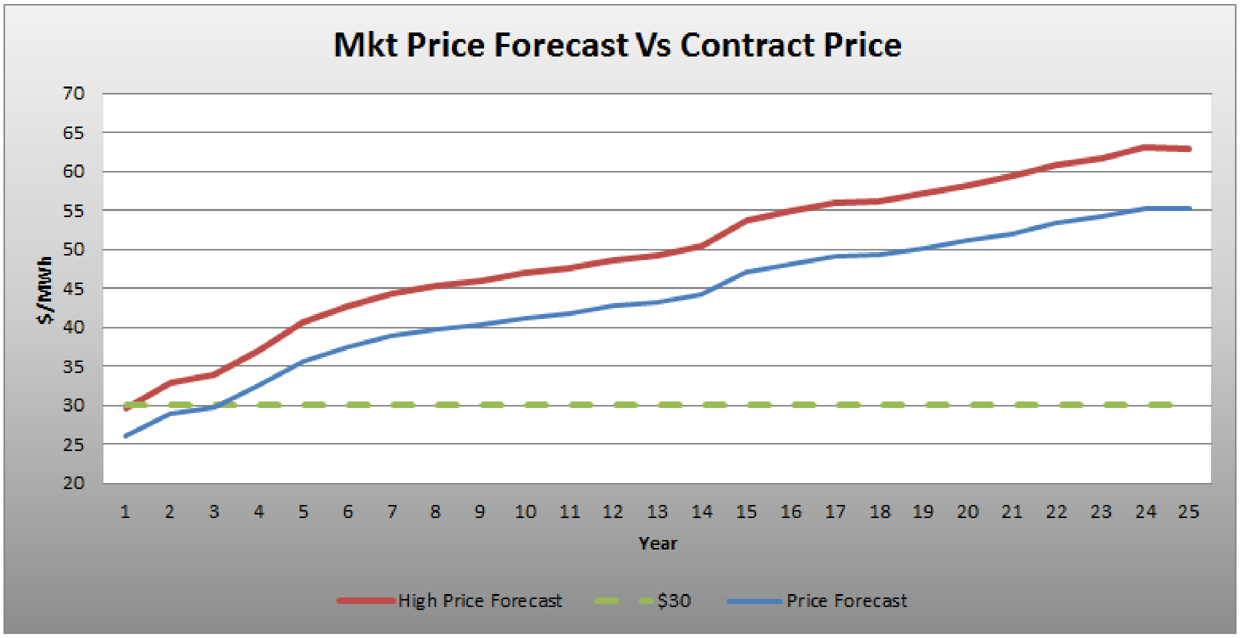
Community Solar Operational Impact Studies			
Facility Type	**Capacity (MW)**	**System Scenario**	**COD**
New Facility	20MW @ $30	Expected Price Forecast	6/1/2018
		High Market Price Forecast	
		Economic Sales	
		3.5% Spin Requirements	
		6% Spin Requirements	
		11% Spin Requirements	
		1 unit required winter; 3 units required in summer	

The key assumptions used in the operational study were:

- Expected Price Forecast
    - 2016 Load forecast
    - Spring 2016 LT price forecast +10%
    - 100% of the "e-Green" Solar Project (CSP) 20 MW project is sold to customers simultaneous to the Commercial Operation Date (COD) of the project built and throughout the life of the project. If the project is not sold, then there will be additional costs that will affect the Rates side. This does not consider the additional costs of revenue losses that may occur if project
    - All projects online and producing as expected by their respective CODs
    - Assumes the contract costs can be achieved through the procurement process. If there is escalation in the contracts of pricing differences, then results will vary.
    - 5% interest rate in NPV calculations
- High Market Price Forecast
    - Use high price forecast of gas/energy prices
- Economic Dispatch Sales
    - Assumes that the day ahead/real time groups economically dispatch to serve load and sell to all accessible markets; separate from term sales
- 3.5%, 6%, and 11% Spin Requirement Scenarios
    - IID would buy spinning reserves to cover difference of spin with solar vs 3.5%, 6%, and 11%
- Seasonal Unit Requirement
    - 1 unit only required during the winter; 3 units only required during the summer

The market price was evaluated at two different levels; the expected market price forecast and high market price forecast. The high market price forecast was evaluated because it represents the 90th percentile of probability distribution using multipliers generated from the Monte Carlo Stochastic analysis. The pricing scenarios are not meant to represent specific future market circumstances but instead are intended to represent the potential price impact of a collection of uncertainties around key market factors affecting the cost and availability of future gas supply. Below is a chart to reflect the $30 contract price, along with the two different market price forecasts.

Exhibit 15: Forecasted market price versus contract price



The table below show the results of the operational study indicating the net present value (NPV) for the multiple scenarios over a 20-year period (chart below are in thousands). All operational studies contain the sale of excess generation (MWh) into the market over the 20-year period.

Exhibit 16: Net Present Value of Annual Costs: System Solutions Tests

System Solutions Test Results								
Year	Expected Price Forecast	High Market Price Forecast	Economic Sales	3.5% Spin Requirements	6% Spin Requirements	11% Spin Requirements	1 unit required winter; 3 units required in summer	Econ Sales + 3.5% Spin + 1/3 units in winter/summer
NPV	$4,062,420	$4,359,610	$3,727,790	$3,751,769	$3,751,822	$4,062,420	$3,757,525	$3,718,362
Rank	6	8	2	3	4	6	5	1

<u>Alternative 1</u>

As shown from the table above, the operational NPV with bringing on a new 20 MW solar project is $4,062,420,000, with the expected price forecast over a 20-year period. The production cost model simulations indicated the combination of 3.5% spinning reserves, economic sales and shutting down one unit had the greatest operational cost impact of $344,058,000. Each of these system wide changes assume a coordinated effort within the Energy Department to ensure risks associated with each system change are mitigated to the greatest extent possible.

<u>Alternative 2</u>

Another option to mitigate excess generation, would be economic sales. The operational impact study revealed economic sales had the second greatest operational savings of $334,630,000 (NPV over a 20-year period). Economic sales would be evaluated on an hourly basis and would utilize internal generation to ramp up/down depending on the market prices. IID's current risk policy does not allow for economic sales; prior to implementing, the policy must be amended and approved.

Alternative 3

Another option to reduce operational cost would be to reduce spinning reserves from the current 11% to either 6% or 3.5%; both indicated savings. Spinning requirements are based on several hourly varying requirements from the Southwest Reserve Sharing Group (SRSG) and the Western Electricity Coordinating Council (WECC). Under normal circumstances, a Balancing Authority (BA) is required to maintain, at a minimum, reserves equal to the loss of the Most Severe Single Contingency (MSSC) or the reserve amount equal to the sum of three percent of the load (generation minus station service minus net actual interchange) and three percent of net generation (generation minus station service). IID must maintain at least fifty percent (50%) of its contingency reserves as spinning reserves. Spinning reserve is the on-line reserve capacity that is synchronized to the electric grid and ready to meet electric demand within ten (10) minutes of a dispatch instruction. Spinning reserve is needed to maintain frequency stability during emergency conditions and unforeseen load swings. The operational savings associated with reducing the spinning reserves from 11% to 6% and 3.5% are $310,598,000 and $310,651,000, respectively. The table below breakdowns the estimated cost to operate at 3.5%, 6%, and 11% spinning reserves. For example, looking at year 2019, if IID were to reduce their spinning reserves from 11% to 6%, the estimated cost savings would be $2,038,219 and if IID were to further reduce their spinning reserves to 3.5%, the estimated cost savings would be $3,057,329.

Exhibit 17: Breakdown of estimated costs of spinning reserves

Est. Spinning Reserve Costs							
Year	Load	3.5% spin	6% Spin	11% Spin	Est. Cost of Spin (3.5%)	Est. Cost of Spin (6%)	Est. Cost of Spin (11%)
2017	3,616,064	126,562	216,964	397,767	$ 1,392,185	$ 2,386,602	$ 4,375,438
2018	3,655,924	127,957	219,355	402,152	$ 1,407,531	$ 2,412,910	$ 4,423,668
2019	3,705,854	129,705	222,351	407,644	$ 1,426,754	$ 2,445,864	$ 4,484,083
2020	3,759,566	131,585	225,574	413,552	$ 1,447,433	$ 2,481,314	$ 4,549,075
2021	3,810,615	133,372	228,637	419,168	$ 1,467,087	$ 2,515,006	$ 4,610,844
2022	3,868,314	135,391	232,099	425,515	$ 1,489,301	$ 2,553,088	$ 4,680,660
2023	3,929,522	137,533	235,771	432,247	$ 1,512,866	$ 2,593,484	$ 4,754,721
2024	3,994,922	139,822	239,695	439,441	$ 1,538,045	$ 2,636,648	$ 4,833,855
2025	4,062,922	142,202	243,775	446,921	$ 1,564,225	$ 2,681,528	$ 4,916,135
2026	4,133,278	144,665	247,997	454,661	$ 1,591,312	$ 2,727,964	$ 5,001,267
2027	4,206,233	147,218	252,374	462,686	$ 1,619,400	$ 2,776,114	$ 5,089,542
2028	4,284,380	149,953	257,063	471,282	$ 1,649,486	$ 2,827,691	$ 5,184,100
2029	4,362,150	152,675	261,729	479,836	$ 1,679,428	$ 2,879,019	$ 5,278,201
2030	4,441,207	155,442	266,472	488,533	$ 1,709,865	$ 2,931,197	$ 5,373,860
2031	4,532,628	158,642	271,958	498,589	$ 1,745,062	$ 2,991,535	$ 5,484,480
2032	4,617,573	161,615	277,054	507,933	$ 1,777,766	$ 3,047,598	$ 5,587,263
2033	4,705,857	164,705	282,351	517,644	$ 1,811,755	$ 3,105,865	$ 5,694,087
2034	4,802,727	168,095	288,164	528,300	$ 1,849,050	$ 3,169,800	$ 5,811,299
2035	4,905,833	171,704	294,350	539,642	$ 1,888,746	$ 3,237,850	$ 5,936,058
2036	5010318.582	175,361	300,619	551,135	$ 1,928,973	$ 3,306,810	$ 6,062,485
2037	5113746.972	178,981	306,825	562,512	$ 1,968,793	$ 3,375,073	$ 6,187,634

Alternative 4

Another option to reduce operational costs would be to shut down one (1) unit in the summer and winter; therefore, only three (3) units would be running in the summer and one (1) in the winter. The unit chosen to shut down was based on unit heat rate. By shutting down one unit, it would mitigate the excess generation with bringing on a new 20 MW facility. The operational cost savings (NPV over a 20-year period) is $304,895.

In summary, a combination of all three scenarios provided the greatest NPV operational cost saving over a 20-year period. A summary of the cost savings associated with each scenario are below along with the ranking.

Exhibit 18: Operational Cost Savings

Operational Cost Savings					
	Economic Sales	3.5% Spin Requirements	6% Spin Requirements	1 unit (Winter); 3 units (Summer)	Econ Sales, 3.5% Spin, 1/3 units in winter/summer
NPV Savings	**$ 334,630.00**	**$ 310,651.00**	**$ 310,598.00**	**$ 304,895.00**	**$ 344,058.00**
Rank	2	3	4	5	1

Financial Analysis

The Finance Rates Section analyzed the "e-Green" Solar Rates, Estimated Number of Subscriptions and Revenue Loss based on a proposed 20 MW Power Purchase Agreement for 25 years. The exhibit below shows the comparison of the cost of solar installation on a kWh basis for a customer in relation to IID's retail energy kWh rate and the "e-Green" solar rate options. The "e-Green" solar rate options include the fixed cost recovery portion of the base energy retail rates, which were determined from the latest retail electric cost-of-service study performed for IID, and the inclusion of the contract price and cost obligations under the Regenerate purchased power agreement that is intended to be utilized for the "e-Green" solar program. This includes the estimated annual payments totaling up to $43.6 million that is applied against the cost of energy which is $37.95/MWh. The annual cross-customer class cost subsidization is approximately $2.3 million (if 20 MW is fully subscribed then the subsidy would be eliminated). All this equates to the "e-Green" Solar Rate. **The rates do not include any program administration, marketing, and SAP billing configuration.**

Exhibit 19: "e-Green" Solar Rate Options

Customer Class	**Cost of Solar Installation $/kWh**		**Existing kWh Rate**	**Community Solar Regenerate PPA**
	Low	High		
Residential	0.1400	0.1700	0.1169	0.1471
Small Commercial	0.1300	0.1600	0.1201	0.1403
Large Commercial	0.1300	0.1600	0.0930	0.1289
Agricultural Pumping	0.1300	0.1600	0.0952	0.1430
Municipal Service	0.1300	0.1600	0.1141	0.1359

If a 20 MW "e-Green" Solar program will be implemented at once or phased in approach. The estimated number of customers listed below will be required to participate in order to fully subscribe the program. These numbers were calculated using average kWh consumption loads.

Exhibit 20: Customer Subscription for 20 MW "e-Green" Solar Program

Customer Class	Potential System Size (kW)	Estimated Number of Customers to Enroll
Residential	1,000	2,036
Small Commercial	2,000	1,728
Large Commercial	13,000	360
Agricultural Pumping	2,000	580
Municipal Service	2,000	765
Total	20,000	5,469

If the FIT option was implemented for the "e-Green" Solar program, below is the estimated number of participants to fully subscribe the program.

Exhibit 21: Customer Subscription for 2 MW "e-Green" Solar Program

Customer Class	Potential System Size (kW)	Estimated Number of Customers to Enroll
Residential	100	204
Small Commercial	200	173
Large Commercial	1,300	36
Agricultural Pumping	200	58
Municipal Service	200	76
Total	2,000	547

The estimated annual cost impact has been determined using the billing rate option. The cross-customer class cost subsidization was calculated using the generation from the solar system as indicated under the draft Regenerate PPA. The annual impact to all retail electric customer is estimated at $2.3 million if the 20 MW program are not fully subscribed. Since this resource is not needed by IID, factored in is an estimated revenue for any excess energy sold in the open market to offset the annual impact to customers. **The annual cost impact does not include any program administration, marketing, and SAP billing configuration.**

Exhibit 22: Estimated Cost Impact

Annual Estimated Impact

Customer Class	Estimated Cost Impact Regenerate PPA	
Residential	$	202,013
Small Commercial	$	456,244
Large Commercial	$	2,411,452
Agricultural Pumping	$	309,419
Municipal Service	$	446,584
Subtotal	$	3,825,711
Value of Solar	$	1,487,624
Net Impact	**$**	**2,338,087**

Therefore, the optimal option would be to use an existing resource so that we implement a pilot "e-Green" program and set lower rates that will incentivize participation while minimizing cost impact and give an opportunity for some revenue recovery.

Additionally, IID can apply a portion of the PBC Fund Balance to help offset the price – the amount will be based on management decision.

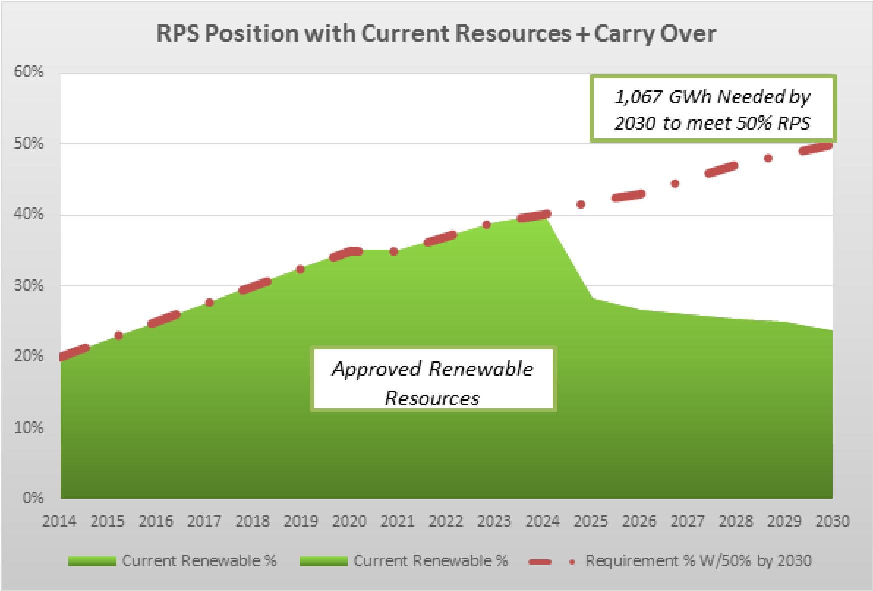
Green-e Energy Program

In terms of developing a Green-e Energy Program it is recommended that participating customers enroll for a flat per MWh monthly fee. This will provide businesses an easy, low-cost way to demonstrate compliance in corporate sustainability objectives. Sacramento Municipal Utility District (SMUD) currently offers a Green-e Energy program in which it voluntarily accepts and supports the Green-e Energy Code of Conduct and Customer Disclosure Requirements and independent verification methods. The Green-E Energy logo means:

- The renewable energy option contains only new renewable resources.
- The sources of energy supplying the renewable energy option are independently verified by Green-e Energy, operated by the non-profit Center for Resource Solutions.
- The purchaser of a Green-e Energy Certified renewable energy option is the sole "owner" of the environmental attributes of a specific megawatt hour (MWh) of energy added to the grid. Independent verification ensures that no MWh are double-counted.
- The company offering the certified renewable energy option agrees to abide by the Green-e Energy Code of Conduct and Customer Disclosure Requirements governing its ethical treatment of customers.

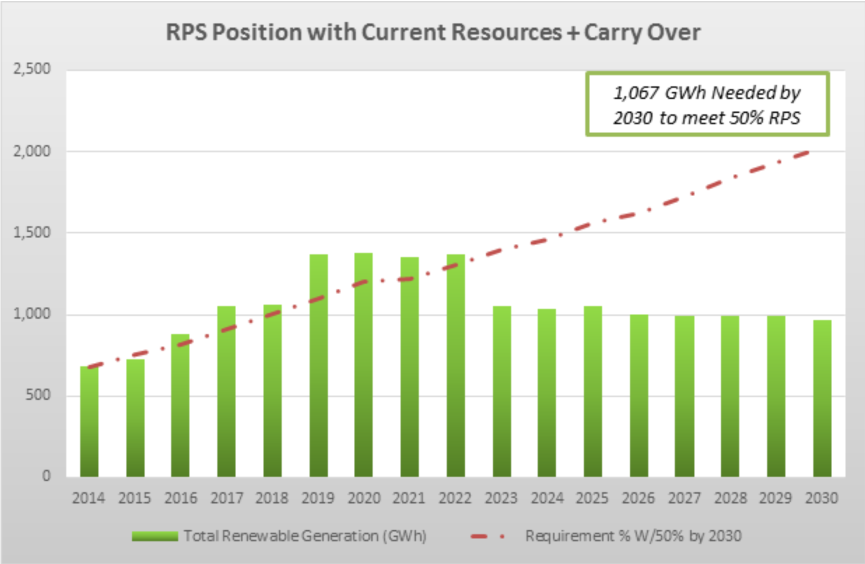
In April 2016, IID's Resource Planning Unit evaluated the impact of selling RECs. The first graph below is the expected case of RPS position, which uses various types of RECs as the measuring unit and is based on normal weather conditions:

Exhibit 23: RPS Position with Current Resources and Carry Over



The chart below shows the REC production by year. Please note, any excess RECs generated in a given year can be retired with the same value for a future period up to 36 months. This is why the first Chart 2 shows a short position in 2025, but the chart below indicates its occurrence sooner:

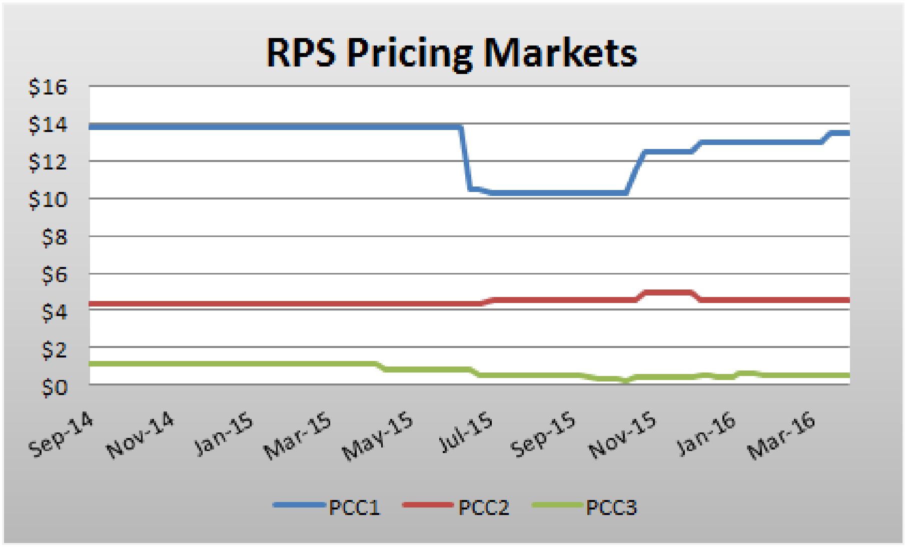
Exhibit 24: RPS Position with Current Resources and Carry Over



As described by the current RPS law and will be described by the upcoming RPS guidelines post 2020, IID can utilize "compliance mechanisms" such as Portfolio Content Categories to minimize cost and operational impacts of RPS compliance. For example: the market value of Portfolio Content Category (PCC) 1 is $13.50/MWrec. A "bundled" product would be the value of the REC + index energy $/MWh. The Index $/MWh = $30/MWh, PCC1 REC $/MWrec = $13.50, then the total renewable energy value =

$43.50/MWh. Below is a chart of RPS pricing markets for each Portfolio Content Category from September 2014 thru March 2016:

Exhibit 25: RPS Pricing Markets



It is important to note that IID's current position of RPS is mainly a result of lower than expected load growth, higher than expected production from RPS facilities and over procurement of RPS resources. Also, the occurrence of non-flexible generation is apparent as IID moves forward with obtaining the RPS compliance. The exhibit below is a forecast of the seasonal over generation for the next five years:

Exhibit 26: Excess Generation Forecast

Over Generation Stats			Summer		Winter	
Year	# hours	MWh	# hours	MWh	# hours	MWh
2016	825	17,241	NA		825	17,241
2017	2,064	66,140	562	25,049	1,502	41,092
2018	26	2,562	26	256	0	0
2019	252	4,775	145	3,376	107	1,399
2020	184	3,443	116	2,595	68	848

As a result, Resource Planning has indicated 2017 is an ideal year to test an RPS sale due to the following:

- The RPS position is very comfortable.
- The hourly excess generation is projected to be high.
- The 2016 market pricing is very low, which translates to a lower sale price.
- A sale in 2016 would likely be much lower than current IID renewable costs.
- A sale could help recover some, but not all the net impact from renewables.
- The 2016 summer capacity (non-natural gas) is needed due to Aliso Canyon concerns.

Some key considerations in a sale are as follows:

- 2017 is an ideal year to test an RPS sale, but the winter of 2016 is a great option, due to the following:
    - *RPS position very comfortable and hourly excess generation is projected to be high*
    - *A sale could help recover **some** of the net impact from renewables; but not all*
- RPS Carry-Over
    - *CEC requires WREGIS retirement within 36 months of REC generation*
    - *Studies show that consistent over production or low loads could cause RECs to build up over a concentrated period to the point that there will be too many RECs to be within the 36 month retirement period and*
- RFP for sale of RPS products
    - *Several parties have expressed interest ranging from $18.50-$22.50/REC + index*
- IID Risk Policy
    - *Need to check with Risk Management to explore if portfolio sale of excess energy/RECs should fall under current language of risk policy*
- Balancing requirements of Seller vs Buyer
    - *Agreement needs to limit the amount IID will balance over/under generation or be 0*
    - *Extra costs of balancing can range from $20-30/MWh*
    - *Generation/Schedule Imbalance Risk*

Resource Planning has indicated four methods of sale:

1. Unit Specific Sale
    a. Market not close to IID costs
    b. For example: ask price can be $55-60, but loss of about $35/MWh
2. RPS Portfolio sale at IID weighted average Variable System Cost
    a. Ask price needs to be above the variable system cost levels to cover market risks (reserves, etc.)
3. Unit specific sale at IID incremental system cost
4. Unit specific sale at current market price
    a. For example: $43.50/MWh, no more $50/MWh less than IID costs

Furthermore, the hours that could be sold that already correlate to the hours where IID is long in overall generation are highlighted in green in the exhibit below using 2017 as the example year:

Exhibit 27: Best Hours to Schedule an RPS Sale

2017											
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
(4)	(15)	(18)	18	49	(31)	(60)	(121)	(31)	(16)	9	(12)
5	(5)	(6)	33	70	(3)	(32)	(90)	(7)	(2)	(17)	(3)
11	1	3	43	85	19	(9)	(66)	12	9	(9)	4
12	4	5	48	95	35	8	(48)	26	14	(6)	6
8	1	3	46	98	43	17	(41)	29	12	(8)	2
(7)	(16)	(12)	41	107	57	27	(40)	20	(3)	(21)	(11)
(32)	(36)	(11)	65	129	76	42	(26)	33	1	(31)	(28)
(25)	(24)	25	93	137	68	38	(28)	52	33	(10)	(20)
15	8	50	96	125	42	8	(57)	36	43	19	4
46	23	52	86	102	3	(30)	(107)	(2)	22	19	25
49	23	45	74	75	(43)	(74)	(164)	(51)	(5)	14	33
47	25	31	57	44	(88)	(118)	(216)	(101)	(35)	7	35
48	22	19	36	10	(133)	(165)	(270)	(150)	(65)	(2)	35
44	17	8	15	(22)	(175)	(202)	(313)	(192)	(93)	(13)	28
35	10	(8)	(8)	(55)	(211)	(234)	(348)	(222)	(121)	(32)	11
(1)	(13)	(29)	(27)	(83)	(242)	(261)	(375)	(252)	(155)	(79)	(19)
(48)	(56)	(69)	(63)	(115)	(272)	(289)	(404)	(288)	(191)	(120)	(64)
(96)	(105)	(108)	(98)	(142)	(293)	(313)	(417)	(293)	(187)	(145)	(104)
(106)	(131)	(130)	(106)	(139)	(285)	(304)	(393)	(262)	(177)	(142)	(109)
(102)	(127)	(138)	(111)	(123)	(253)	(275)	(360)	(237)	(162)	(134)	(106)
(95)	(118)	(128)	(102)	(108)	(224)	(245)	(326)	(202)	(137)	(122)	(99)
(74)	(95)	(102)	(73)	(72)	(178)	(200)	(273)	(156)	(104)	(99)	(83)
(45)	(62)	(67)	(36)	(23)	(121)	(146)	(213)	(104)	(66)	(71)	(56)
(18)	(34)	(38)	(4)	18	(71)	(96)	(160)	(59)	(34)	(41)	(30)

A unit specific or portfolio based sale would require hourly analysis. All methods provide a revenue stream and can recover costs, but the market costs will need to be evaluated. A REC program will not reduce participating customer bills, but will provide green attributes for a fixed cost on top of the monthly bill.

Customer Education and Survey

Although significant time and resources have been dedicated toward development of this business case, it lacks one very important element - a survey of our customers. In order to achieve full subscriptions for the Community Solar and “e-Green” Energy programs, it is critical that we understand demographics, new product acceptance and customer attitudes and expectations. It is therefore, the team’s recommendation to first develop a market study or survey to gauge the level of interest for a “e-Green” solar program and a Green-e Energy Program. Concurrently, an educational outreach effort should be conducted to inform customers of the benefits of such programs.

While this particular study analyzed a bevy of factors and considerations, IID will need to continue to run assessments that fully consider pros and cons of various application of this type of program. Additionally, a comprehensive analysis should be completed with the benefits clearly outweighing the costs in order to begin implementing a specific application.

VEHICLE ELECTRIFICATION POTENTIAL

IID has studied the potential impacts of providing a program(s) that incentivize customers to buy and utilitize electric vehicles. The main goal was to analyze any impacts on the utility and the consumer to explore any realizable value in a program that complies with SB350s guidelines. Some of the key considerations that are important in a vehicle electrification program and its costs and benefits are as follows:

- *Cost per mile*
- *Driving range*
- *Energy input to IID system*
- *Charging time*
- *Type of Vehicle (BEV/PHEV)*
- *Consumer Perspective*
- *Program risks*
- *Vehicle Market Share*

Nationally, the number of electric vehicles is increasing significantly due to better technology, state regulation and lower vehicle prices; as a result of this several nationwide pilot programs are put in place for Battery Electric Vehicles (BEV) and Plug-In Hybrid Electric Vehicle (PHEV). Integrating Electric Vehicles have a direct impact to utility energy grid, and there are many variables we need to take in consideration for move to the Vehicle Electrification Programs, such as types of charging stations, electric vehicles characteristics, possible charging hours during the day, and how these variables affect energy utilities system.

Vehicle Sales

In the last years California has increase the electric vehicles sales; since 2011 to Aug'16 the total national sales were 496,190 and California had 231,482 this represents the 47% [1]. If we compare the month of August of 2016 national sales was 14,973 and in California 7,786 this gave a participation of 52% [1] of electric vehicles. Most of these sales are concentrates in the metropolitan areas such as Los Angeles, Sacramento, San Francisco, San Diego, etc. where utility companies put in place rebate programs to promote vehicle electrification especially on residential customers.

Charging Stations

In the market exist 3 charging stations categories, that are "Level 1" based on a 120V circuit, "Level 2" a 240V circuit, and "Level 3" a DC/fast-charging. A summary of charging time and costs are show below.

Exhibit 28: BEV & PHEV Changing Stations Categories Summary

Charging Time	Cost (dlls)	BEV (hrs.)	PHEV (hrs.)
Level 1 (120V)	600	12-19	5-13
Level 2 (240V)	1,600	1-4	1-2
Level 3 (480V)	22,700	< 0.5	< 0.3

For Level 1 the cost is for the plugging cord, no electric circuit modification is needed and can be connected to the normal 120V receptacles (electric outlets) at home.

Regarding Level 2 in last year and 2016 charger installation increase due to the Federal tax credit which depends on the size of the vehicle and its battery capacity and can go up to 1,000 dollars [2], also utilities are offering rebates that can go up to 500 dollars [3] for residential installations. Most of the utilities that offers this rebates program are expecting more Level 2 residential installations, and a typical setup is a 240-V system based on a 30Amps circuit. Manufacturing companies are investing on optimize Level 2 chargers, in the market it is available only the 30-amp system, they are working on 40-amp or higher systems that can reduce in half the charging time in comparison with the existing 30-amp system. Additionally, the amperage of the chargers used in each vehicle can change the charging times. The table below illustrates these time variances:

Exhibit 29: Charing Time Variances of Level 2 Changing Station

Level 2 (240V)			
Amps	kWh	Charging Time * (hrs.)	Charger Cost Only **
30	7.2	4.17	$ 689.00
40	9.6	3.13	$ 835.00
50	12	2.50	$ 899.00
70	16.8	1.79	$ 2,195.00
80	19.2	1.56	$ 2,195.00

*** Consider a fully charge of a 30kWh battery.**

**** Do no include permit and installation cost.**

A typical charger size for a level 2 is a 30amps system which can fully charge a 30kWh battery in approximately 4.17 hours, as we increase the amperage we reduce the charging time. Level 2 chargers can go up to 80 amps, and by moving to this amperage rating charging time can be reduce to 1.56 hours. Customers need to take in consideration that increasing the amps reduce charging time and also increase the cost of the charging stations.

No plans for the near future for Level 3, this will be commercial only.

[1] http://www.pevcollaborative.org/pev-sales-dashboard

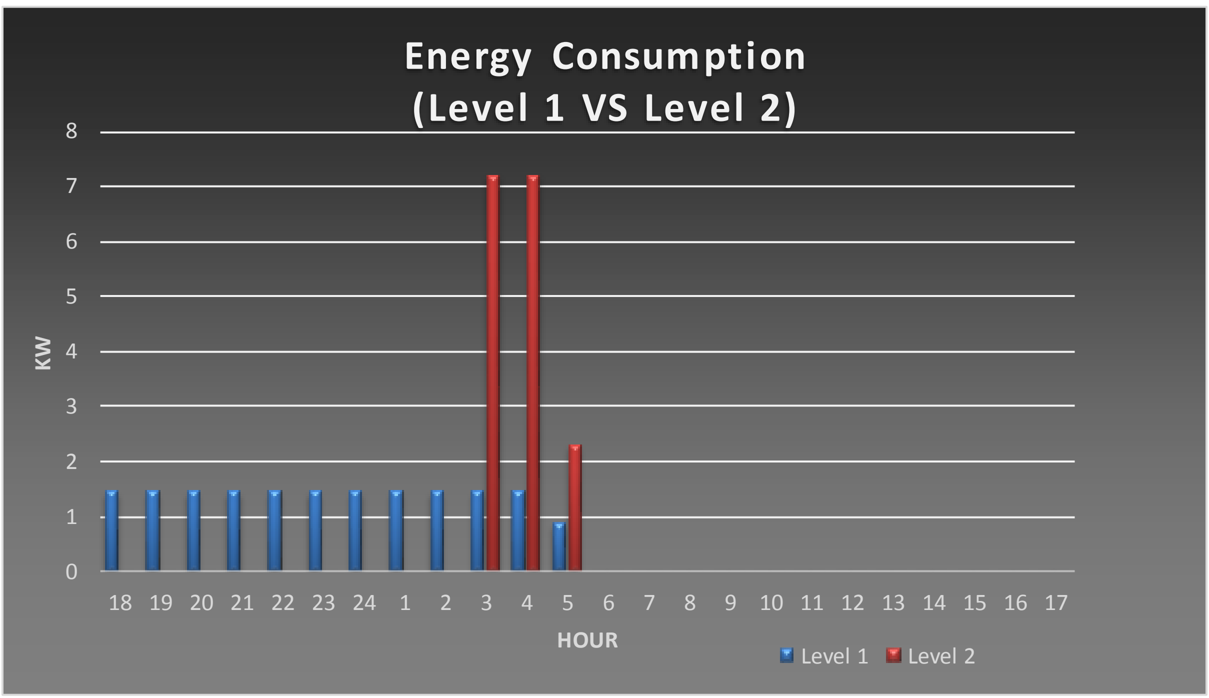
[2] http://www.afdc.energy.gov/laws/10513

[3] https://www.epa.gov/cati/workplace-electric-vehicle-charging-stations-californias-south-coast#incentives-veh-install

Electric Vehicle Charging Habits

In the past all analysis/calculation was made assuming how many hours the electric vehicles needed to be 100% charge, and was taking in consideration that most of electric vehicles charging occurs during night hours (start charging at 7PM or 8PM). In the last quarter of 2015 when the majority of the new customer change from Level 1 to level 2 we have a different energy consumption shape, c~~ustomer plug in the vehicle~~ the logic of the charger is different. Level 2 devices setup an hour at the one the vehicle need to be 100% (in most common cases is 6AM). The graph below reflects the energy consumption between level 1 & Level 2 chargers.

Exhibit 30: Energy Consumption of Level 1 & Level 2 Changing Stations



The graph is taking in consideration a single customer that one starts charging the vehicle at 6PM, and they need to have 100% charged by 5AM.

Consumer Transportation Impact

In the next analysis we calculate the cost per mile for the three categories (gasoline, PHEV and BEV). Several models and manufacturer were analyzed and the table below shows the average. For compare each category was used dollars per mile ($/mi) units.

For all the vehicles we assume a total of 120,000 miles for the life term of the units. The cost is taking in consideration two factors, that are the vehicle cost and the fuel cost. For the vehicle cost we divide the total cost of the vehicle by 120,000 miles. Only for BEV and PHEV tax credit was applied to the total cost of the vehicle, credit depends on the type of vehicle and battery size.

And for the fuel cost all units was analyzed separate and take in consideration the type of vehicle, engine efficiency, battery size, and other variables that can affect the cost per mile. The variables stay constant to all the vehicles analysis was the energy price and the fuel price.

The energy residential rate was the same for all vehicles and was 13.9 cents per kWh, and the same applied to the fuel cost was use 2.79 dlls/gl on along the study.

Exhibit 31: PHEV & BEV Characteristics

Vehicle Characteristic	Gasoline	Plug-In Hybrids Vehicles (PHEV)	Battery Electric Vehicle (BEV)
Range	307-564	420-610 (21-53 Electric Only)	68-215
MPG	30	39	-
kWh/mile	-	0.358	0.281
Total Annual Energy Use (MWh) – IID Fleet	-	3,500	5,250
Total Annual Energy Use (MWh) – Customer Program (**15%**)[1]	-	89,813	128,520
Vehicle Cost (dlls/mi)[2]	$0.153	$0.230	$0.172
Fuel Cost (dlls/mi)	$0.096	$0.056	$0.040
Total Cost (dlls/mi)	**$0.249**	**$0.285**	**$0.212**

BEV have the better cost of 0.212 $/mi but we need to considerer that the mile range goes from 68-215 miles per battery 100% charged. BEV customers need to charge at home, not too many charging stations are in Imperial Valley so in most of the cases we are taking in consideration a 34-107 miles' radius travel from home. PHEV have a better mile range (420-610) but they have a highest cost of the three categories 0.285 $/mi, one of the factors is that most of the PHEV receive a percentage of the tax credit while BEV can have 100% of the tax credit.

Gasoline engines have the highest share in the market, the cost per mile is higher than the BEV, and lower than PHEV. Gas based motors have a minimum loading tank comparing to 100% charging time of BEV, also gas stations are available along the Imperial Valley and the US.

In the last year Fuel Cells Vehicles (FCV) has been introduce to the market, the fuel FCV in a technology that use hydrogen as fuel and is a zero emission unit. FCV cost are higher in comparison to BEV, PHEV and conventional gas engines, in the US there are not too many hydrogen stations and recharge fuel time is very similar to the gas based engines.

Various Vehicles Observed

Models selected for the study are the ones that represent 90% of the nationwide market share. The first part (highlighted in red) are the BEV and the next section (highlighted in blue) is the PHEV portion. We also include an estimation hours of charging time, this section is divided by Level Type and the calculation is based on the battery size of each vehicle. In the table below are the models we analyzed, the

Exhibit 32: BEV and PHEV cost analysis by vehicle models

Company	Model	Battery Size (kWh)	Mile Range	Vehicle Cost	Vehicle Cost (After Tax Credit)	Vehicle Cost ($/mi)	Fuel Cost ($/mi)	Total Cost ($/mi)	Level 1 (120V / 12A)	Level 2 (240V / 30A)	Level 3 (480V / 80A)
Nissan	Leaf	24	84	$29,010	$21,510	$0.179	$0.040	$0.219	16.67	3.33	0.36
Tesla	Model S 60	60	218	$66,000	$58,500	$0.488	$0.038	$0.526	-	1.17	0.10
Tesla	Model 3	55	215	$35,000	$27,500	$0.229	$0.036	$0.265	-	1.17	0.10
Fiat	500e	24	87	$31,800	$24,300	$0.203	$0.038	$0.241	16.67	3.33	0.36
Ford	Focus EV	23	76	$29,170	$21,670	$0.181	$0.042	$0.223	15.97	3.19	0.35
Smart	forTwo EV	17.6	68	$20,440	$12,940	$0.108	$0.036	$0.144	12.22	2.44	0.26
VW	e-Golf	24	83	$28,995	$21,495	$0.179	$0.040	$0.219	16.67	3.33	0.36
Chevrolet	Spark EV	24	82	$25,995	$18,495	$0.154	$0.041	$0.195	16.67	3.33	0.36
KIA	Soul EV	27	93	$31,950	$24,450	$0.204	$0.040	$0.244	18.75	3.75	0.41
Chevrolet	Volt	18.4	420	$33,220	$25,720	$0.214	$0.048	$0.263	12.78	2.56	0.28
Ford	Fusion Energi	7.6	610	$31,120	$27,113	$0.226	$0.060	$0.286	5.28	1.06	0.11
Ford	C-Max Energi	7.6	553	$31,770	$27,763	$0.231	$0.060	$0.291	5.28	1.06	0.11
Hyundai	Sonata Plug In	9.8	600	$34,600	$29,681	$0.247	$0.055	$0.302	6.81	1.36	0.15

BEV and PHEV units can receive a Federal tax credit up to $7,500. Tax credit depends on the battery size of the vehicles, with a minimum battery pack of 4kW for $2,500 and $7,500 for a 16kW or more.

PHEV vehicle cost is higher than BEV, but they have a less charging time due to the hybrid electric/gas engine. BEV customer charge the units at night, and there are a few charging stations at the workplace. available Mile range is better for PHEV.

Most of the PHEV customer charge automobile once a day and when the battery is discharged the engine switch to gasoline. For the BEV is a different condition because there is no alternate fuel and this affects the customer habits. Three types of scenarios are analyzed under BEV units.

1) One Charge per day. Customers need to be plug the vehicle at home and have the unit 100% charge for a certain hour in the morning (50% of the customers are in this category)
2) Two Charges per day. Customers need to be plug the vehicle at home and have the unit 100% charge for a certain hour in the morning, and also they charge the vehicle at work (36% of the customers).
3) Three charges per day. Customers need to be plug the vehicle at home and have the unit 100% charge for a certain hour in the morning, charge the vehicle at work, and another charge at home after work (14% of the customers)

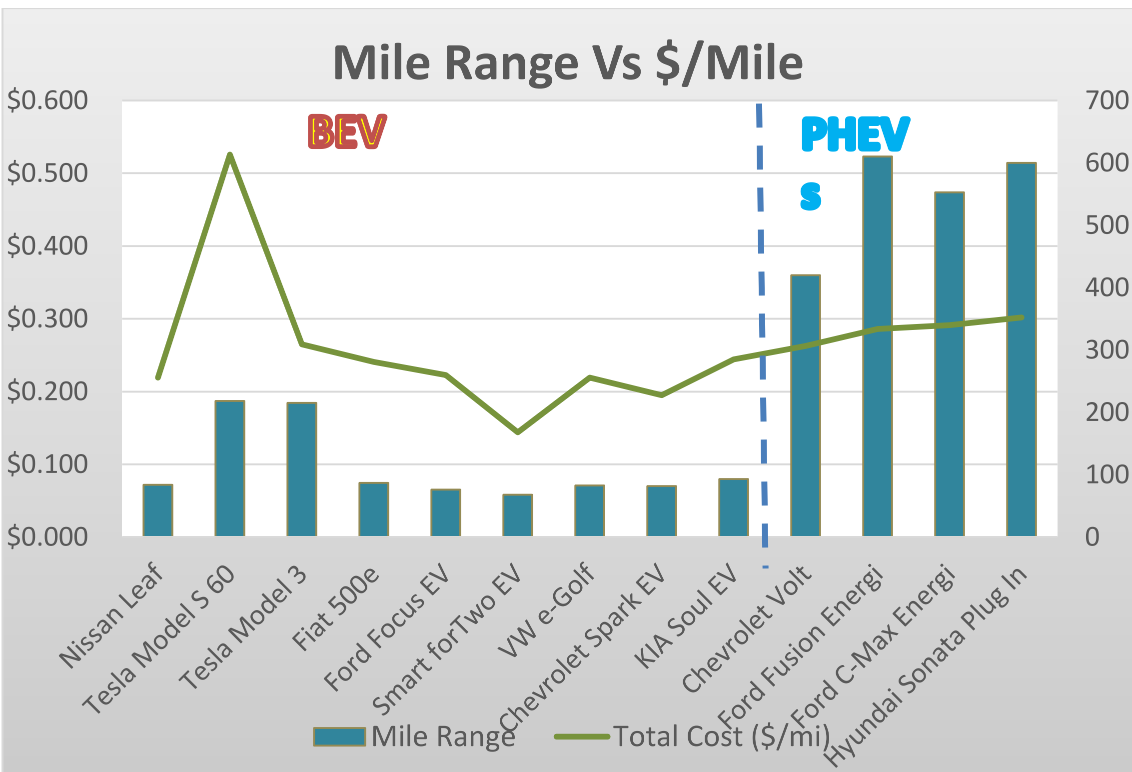
When customer need to charge more than once a day and the charging time is a limitation to use the vehicle, customers strongly prefer shorter charging periods. Install a Level 2 charging station cost approximately $1,600, and in some cases double this price due to extra modification to their electric system, this is the main reason customer do not migrate from Level 1 to Level 2. Utilities setup rebate programs for customers that install Level 2 charging stations, this is to incentive residential and commercial customer. In general, as more customers connect to the grid the better benefits because can complement and balance intermittent renewable energy.

Mile range and charging time are very strong variable that customers analyze before moving to vehicle electrification. The next graph we put together all the vehicle and the bars illustrate the total miles per fully charge, the green line represents the cost per mile for each vehicle.

Most of the BEV have a better cost in comparison with the PHEV, and we can observe that the mile range is better for PHEV's.

The graph below illustrates mile range and cost per mile between BEV and PHEV.

Exhibit 33: Mile Range and Cost Between BEV and PHEV



As a result, PHEV have higher costs and the market share is lower than BEV. Customers are considering the first BEV instead of PHEV, the limitations for BEV is the mile range.

Analysis of Potential Programs

Based on the information above, IID observed several program structures and their impact potential. Furthermore, the investment potential and return of revenues through greater loads was used to determine the potential value of a program. The two basic programs studied were as follows:

- Charging station rebate
  For customer Level 1 is a good option, is the lowest cost in most of the cases, no modifications to the existing electric circuit, and charging time is longer (usually charge vehicle at night hours). Level 2 can reduce the charging time in a half but require customer investment. Level 2 minimize intermittent impacts due to renewable resources, more customers interconnect are better to the utility electric system. IID can promote Level 2 installation with a rebate program for residential and commercial customers. Most of the utilities in California offer rebates up to $500 per residential charging stations and $1,000 for commercial applications.
- Charging station based program (describe)
- Customer based program (describe)

The coverage scenarios and the estimated saturation levels for the studies are as follows:

- **Total cars estimated for all IID customers:**
  - ***Approx 214,423***
- **Scenarios studied of total saturation of all vehicles in IID area converted to BEV or PHEV and incentivized to charge batteries:**
  - ***5%***
  - ***15%***
  - ***30%***
- **Each scenario added a certain amount of energy (i.e., revenues) to the IID system that was calculated and attributed to the public program**

The results were observed in two forms:

1. **A single year return on investment**
2. **10 year NPV return on investment**

Below are two tables that summarize the two versions:

Single Year

Exhibit 34: BEV & PHEV System Impact and Public Programs Potential (Singer Year)

SYSTEM IMPACT		BEV			PHEV		
		5%	15%	30%	5%	15%	30%
ENERGY (MWH)		36,214	108,643	217,285	54,814	164,443	328,886
ADDED REVENUE		$5,033,746	$15,101,377	$30,202,615	$7,619,146	$22,857,577	$45,715,154
SAVINGS AMOUNT		$2,679,836	$8,039,582	$16,079,090	$4,056,236	$12,168,782	$24,337,564
70% OF ENERGY TRADEOFF		$1,875,885	$5,627,707	$11,255,363	$2,839,365	$8,518,147	$17,036,295
PUBLIC PROGRAM POTENTIAL							
CHARGING STATION BASED PROGRAM	# CHARGING STATIONS 1	3,126	9,380	18,759	4,732	14,197	28,394
	# CHARGING STATIONS 2	1,172	3,517	7,035	1,775	5,324	10,648
	# CHARGING STATIONS 3	83	248	496	125	375	750
CUSTOMER BASED PROGRAM	INCENTIVE PER CAR SOLD	$175			$265		

Exhibit 35: BEV & PHEV System Impact and Public Programs Potential (10 Years)

SYSTEM IMPACT		BEV			PHEV		
		5%	15%	30%	5%	15%	30%
10 YEARS SAVINGS AMOUNT		$26,798,360	$80,395,820	$160,790,900	$40,562,360	$121,687,820	$243,375,640
70% OF ENERGY TRADEOFF		$18,758,852	$56,277,074	$112,553,630	$28,393,652	$85,181,474	$170,362,948
PUBLIC PROGRAM POTENTIAL							
CHARGING STATION BASED PROGRAM	# CHARGING STATIONS 1	31,265	93,795	187,589	47,323	141,969	283,938
	# CHARGING STATIONS 2	11,724	35,173	70,346	17,746	53,238	106,477
	# CHARGING STATIONS 3	826	2,479	4,958	1,251	3,752	7,505
CUSTOMER BASED PROGRAM	INCENTIVE PER CAR SOLD	$1,750			$2,648		

Grid Impact

If the number of electric vehicles increase significantly, additional grid studies require to determine if system upgrade or modifications are need to support the extra energy demand. Several actions plans can put together before start upgrading the electrical system, such as

- Monitor and track the consumptions shapes and try to optimize charging station by start them when energy begins to decrease (as example when air conditioning units are not running).
- Other utilities along the US have two energy prices, utilities offer a lower kWh price during the hours that the energy begins to decrease (usually at night hours).

These are the significant impacts, IID need to track each circuit and monitor the quantity and demand of the electric vehicle charging station.