Speaking points for Feb. 21st public meeting on PSE's IRP Plan

Michael Laurie, Feb. 19, 2018

Thanks for this opportunity to present some of my thoughts on PSE's IRP.
My name is Michael Laurie. I have over 30 years of experience working in residential, commercial, and industrial conservation. I have carried out commercial and residential energy efficiency audits and inspections in PSE's programs. I live on Vashon Island and I am a PSE customer.

Renewable energy is winning. It is winning most of investments for new electricity in the US and around the world and it is starting to win the competition as the lowest cost resource. And clearly renewable energy is where we must go if we are to have any hope of reducing the increasing economic and social costs of climate change. Renewable energy is our future.

My worry is that unless we, the WUTC, and PSE fully recognize and act now like renewable energy is the future, that we will postpone that future at great expense to all of us.

Recognizing now that renewable energy is our future means that PSE needs to take many big steps to help make the transition to that safe future as reliable and low cost as possible.

That means they need to continue and expand the great energy efficiency and renewable energy programs they have successfully running for year.

That means they need to invest heavily in a full range of storage technologies in a wide range of locations. That means putting storage in their grid in different places to learn where and when it makes the most sense. It means paying rebates to customers for installing storage in their homes and businesses so that PSE can learn how customer storage can best play a role in the coming renewable energy dominated system.

It means that PSE needs to heavily invest in a range of peak demand reduction actions that will reduce the need for natural gas plants. Two recent papers provide some detail on this

"Teaching the Duck to Fly" a recent paper by Jim Lazar points to 10 steps that can be taken to reduce the electricity demand curve through a range of actions including controlling water heaters, commercial ice storage, demand response, rate design, and more.

Demand Flexibility: The Key to Enabling a Low-Cost, Low-Carbon Grid by the Rocky Mountain Institute, "shows how demand flexibility can be a lower-cost, less-polluting alternative to natural gas-fired power plants for balancing renewable energy on the grid."

PSE needs to invest now in other grid related changes that will be needed or may be needed to allow their grid to better handle a growing percentage of renewable energy.

Why am I suggesting all this spending on storage, demand management, energy efficiency, grid changes, and renewable energy now, when it looks like PSE in the short to medium term plans to rely on purchasing energy available from other suppliers?

I am worried that if PSE just goes along pretty much with business as usual with limited attention to the topics I raised, they risk reaching a point soon where business as usual and power purchases in the open market will not be enough to make up for the loss of generation from the Colstrip plants that I would like to see all closed by 2025.

And if PSE does not start investing heavily in these renewable friendly, future friendly energy system changes, and gain experience with which pieces make the most sense when and where in their system, they may find themselves backed into a corner where they feel that building future destructive natural gas plants are their only choice.

I ask you commissioners to ask PSE to invest much more heavily now in renewable energy, energy efficiency, storage, demand management, and grid changes to be fully prepared for the renewable energy future that we all know is coming. Thanks, you for your time.

652 words, 130 words per minute. 722 words/130 words per minute = 5 minutes

DEMAND FLEXIBILITY

THE KEY TO ENABLING A LOW-COST, LOW-CARBON GRID

INSIGHT BRIEF

February, 2018

HIGHLIGHTS

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- Wind and solar energy costs are at record lows and are forecast to keep falling, leading to greater adoption, but the mismatch of weather-driven resources and electricity demand can lead to lower revenues and higher risks of curtailment for renewable energy projects, potentially inhibiting new project investment.
- Using an hourly simulation of a future, highly-renewable Texas power system, we show how using demand flexibility in eight common end-use loads to shift demand into periods of high renewable availability can increase the value of renewable generation, raising revenues by 36% compared to a system with inflexible demand.
- Flexible demand of this magnitude could reduce renewable curtailment by 40%, lower peak demand net of renewables by 24%, and lower the average magnitude of multihour ramps (e.g., the "duck curve") by 56%.
- Demand flexibility is cost-effective when compared with new gas-fired generation to balance renewables, avoiding approximately $1.9 billion of annual generator costs and 20% of total annual CO_2 emissions in the modeled system.
- Policymakers, grid operators, and utility program designers need to incorporate demand flexibility as a core asset at all levels of system planning to unlock this value.

INTRODUCTION

THE MERIT-ORDER EFFECT, AND THE OPPORTUNITY FOR DEMAND FLEXIBILITY

More than half of the electricity generation capacity added to the U.S. grid in 2016 and 2017 came from renewable resources, largely driven by the precipitous price decline of wind and solar projects. While this scale of renewable generation has translated into millions of tons of avoided carbon emissions, this increase in supply also has implications for wholesale electricity markets. Because of its very low marginal costs, renewable generation displaces more-expensive producers, resulting in lower wholesale clearing prices, and in some circumstances leading to curtailment; i.e., forced reduction in power output. As the penetration of variable renewables increases and the risk of curtailment grows, new renewable capacity is exposed to lower prices. This value deflation can reduce the revenues of renewable projects, making the investment in and development of new renewable projects less attractive.

However, leveraging opportunities to shift load to better match the supply of renewables can mitigate the impacts of this value deflation. For years, utilities and market operators have used traditional demand response programs to send signals to consumers to reduce electricity consumption at times of high stress on the grid. Now, a new generation of communication and control technologies can enable "demand flexibility," allowing major loads to continuously respond to changing renewable supply levels and other market signals.

Solar photovoltiacs' (PV's) impact on the grid most clearly illustrates the potential mismatch between renewable supply and end-use demand—and the opportunity for demand flexibility to address this mismatch. While solar generation reaches its peak around midday when the sun is high in the sky, peak demand usually occurs later in the afternoon and early evening as temperatures peak and families return home. To adjust this misalignment, demand flexibility technologies can shift electricity consumption from times of high load to hours with high renewable availability.

This load shift reduces overgeneration, lowers peak demand, and mitigates the steep ramping needed to serve high midafternoon electricity needs as the sun goes down. Previous RMI work has shown that demand flexibility can result in significant benefits at the household level. Figure 1 illustrates how a simulated residential customer in Hawaii could shift household electricity consumption to the middle of the day when PV generation peaks by using a suite of technologies, including battery energy storage, managed electric vehicle charging, and smart air conditioning controls.

Figure 1: Impact of demand flexibility on residential load profile

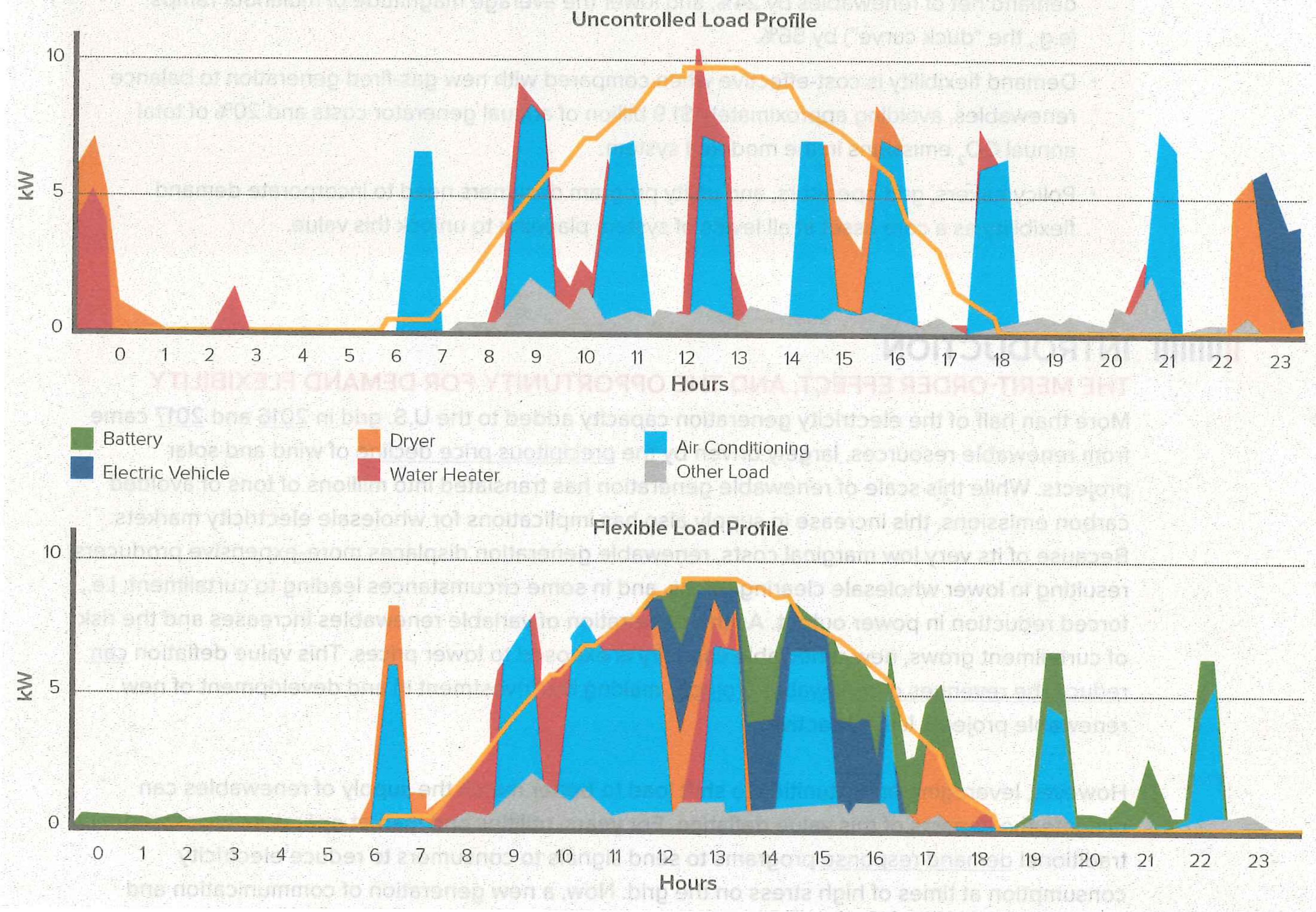
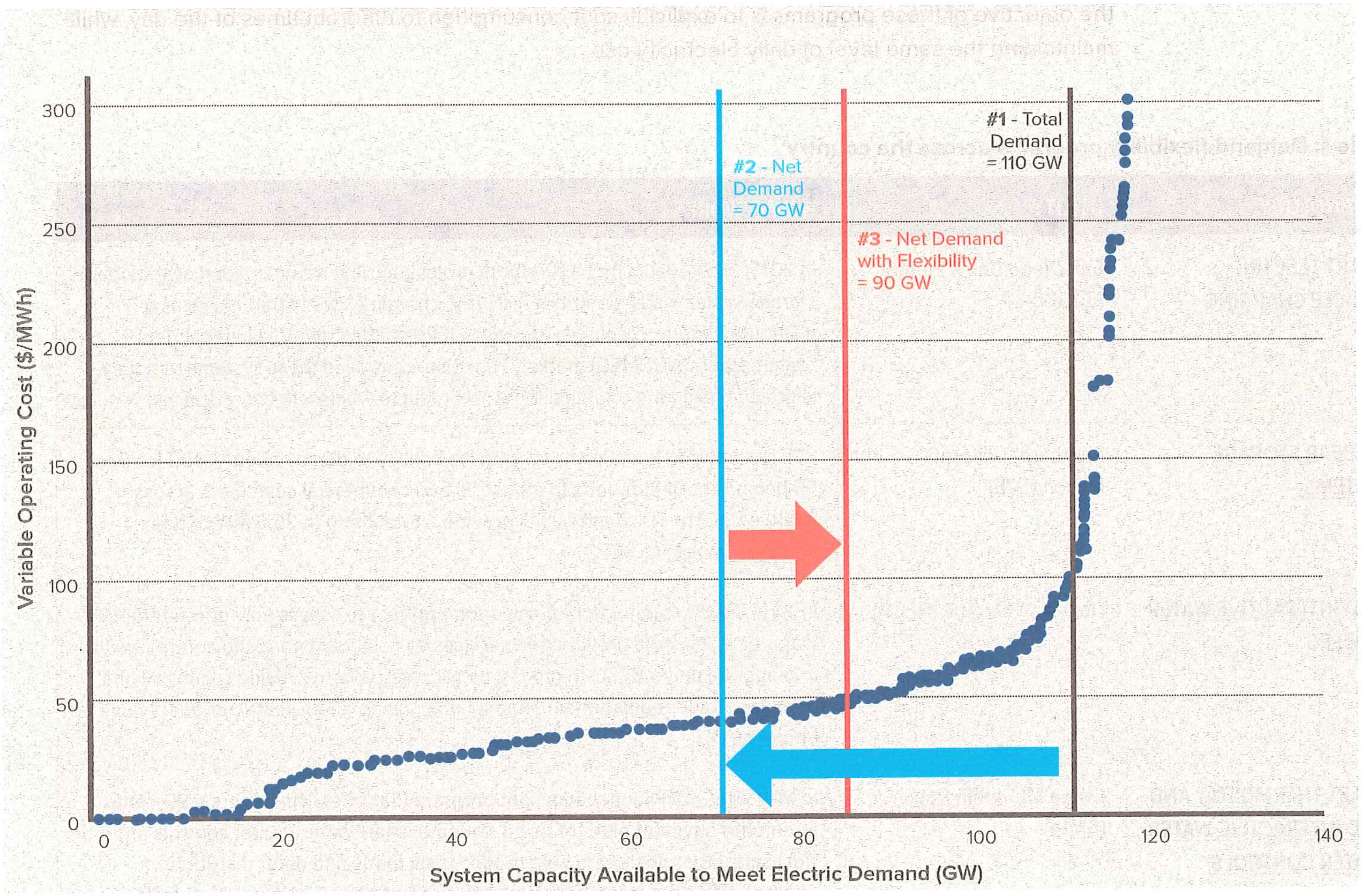


Figure 1's two different load profiles show how using automated communication and control technologies can shift electricity use across hours of the day, without any significant impact on the quality of service that a customer would receive from those end-use loads, and without requiring that customers are at home in the middle of the day waiting to use their washing machine during opportune times. At the household level, these demand flexibility technologies can lead to increased self-balancing and retail bill savings between 10% and 40%; at the level of a regional grid, the same technologies can significantly mitigate the price impacts of renewable energy.

Figure 2 below uses a representative dispatch curve for ERCOT's service territory to show both the regional impact of renewable energy on clearing price in the wholesale market, as well as the mitigating effects of demand flexibility. The long blue arrow shows the impact renewable energy has on the clearing price: variable renewable energy reduces load that must be met by thermal generators, and the marginal cost to meet load declines accordingly, causing generator revenue to fall. However, increasing demand at times of high renewable availability, as illustrated by the red arrow, can raise this price, increasing revenues for renewable generation.

Figure 2: Impact of renewables and demand flexibility on the wholesale market



THE EVOLVING ROLE OF DEMAND FLEXIBILITY

Utilities and system operators have decades of experience in deploying demand flexibility technologies to provide value to the grid, and increasingly to integrate variable renewable energy. Over 600 utilities have already deployed rate structures that reflect a more granular value of consumption, allowing customers that adopt flexibility technologies (e.g., smart thermostats) to realize sizeable bill savings as well as cost benefits at the system level.

Utilities across the U.S. are now considering demand flexibility as an important component of "non-wires alternatives" that can defer large infrastructure investments. For example, Central Hudson's CenHub Peak Perks program compensates customers residing in key geographic areas to reduce energy use during times of peak demand using a Wi Fi-enabled smart thermostat or a program efficiency switch. Both Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) in California have initiated a number of projects focused on non-wires alternatives to support distribution system reliability and to address natural gas leaks, retirement of nuclear power plants, and particular areas of significant load growth. In Washington, Bonneville Power Authority recently gave up a long-term effort to build over $1 billion worth of new transmission and will be addressing this need with procurement of non-wires alternatives instead.

Table 1 describes a number of programs that have leveraged the capabilities of demand flexibility technologies to bring value to the grid. These offerings differ from traditional demand response programs as they are not designed to simply curtail consumption during times of high load; rather, the objective of these programs is to explicitly shift consumption to different times of the day, while maintaining the same level of daily electricity use.

Table 1: Demand flexibility programs across the country

TECHNOLOGY	UTILITY	HOW IT WORKS
SMART ELECTRIC VEHICLE CHARGING	San Diego Gas & Electric (SDG&E)	In 2015, SDG&E launched a 10-month project utilizing a combination of stationary storage systems and electric-vehicle (EV) charging sites to participate as a distributed energy resources provider (DERP) in the California Independent System Operator (CAISO) market. The utility controlled these systems remotely, charging EVs during off-peak hours according to wholesale energy prices.
ICE BEAR STORAGE SYSTEMS	Southern California Edison (SCE)	SCE has entered into a contract with Ice Energy to deploy about 1,800 Ice Bear 30 behind-the-meter units to industrial and commercial customers across Orange County. The devices will provide a total of up to 25.6 MW of peak storage capacity to SCE.
GRID-INTERACTIVE WATER HEATERS	Hawaiian Electric (HECO)	In 2014, HECO commissioned a yearlong project to assess how grid-interactive water heaters could provide grid services by using software and controllers to manage the units. HECO found the project was able to provide sustained and precise voltage regulation and had a minimal impact on customer energy use or comfort.
SMART-THERMOSTAT AND GRID INTERACTIVE-WATER HEATER CONTROLS	Green Mountain Power (GMP)	In May 2017, GMP launched a pilot program that offers customers a 99-cents-per-month payment plan for using Aquanta smart water-heater controls and Nest smart thermostats to help reduce peak loads and defer distribution upgrades. Participants also allow GMP to access the these smart controls in aggregate, within certain parameters, to maintain comfort, allowing GMP to use these devices to meet its larger grid needs (e.g., to reduce system-wide capacity charges, to mitigate congestion on distribution circuits, etc.)
ELECTRIC THERMAL STORAGE	Tri-County Rural Electric Cooperative	Tri-County offers a rebate of $50 for every kW of installed electric thermal storage (ETS) to homeowners. The ETS units are expected to use lower-cost off-peak electricity to heat ceramic bricks in an insulated cabinet and then release this heat continuously. The utility offers a time-of-use ETS Rate for participating customers.

DEMAND FLEXIBILITY MODELING PARAMETERS

This paper seeks to characterize the potential of demand flexibility programs deployed at scale, in a future highly renewable power system. To do this, we start with an assessment of the flexibility present in eight end-use loads in the residential and commercial sectors that do not need to be run on a fixed schedule to meet customers' end-use needs. We model the wholesale electricity market in Texas, ERCOT, because it has significant renewable growth potential and it represents a system "islanded" from the broader U.S. grid and thus a natural test case for the potential of demand flexibility to balance renewable variability. We use RMI's 2012 Reinventing Fire analysis of forecasted load in 2050 by major end uses, including the additional load expected from the increase in electric vehicle adoption, to parameterize the magnitude of load in each of the eight modeled end uses. Table 2 describes each of these end-use loads, and their associated parameters used in the analysis.

Table 2a: Eight flexible end-use loads used in model

ASSUMED FLEXIBILITY LEVERS	INCREMENTAL COSTS	NUMBER OF FLEXIBLE LOADS MODELED	FLEXIBILITY MODELING ASSUMPTIONS
RESIDENTIAL ELECTRIC WATER HEATERS	$5 per controlled device (Source: technology developer interviews)	3,900,000 households with electric water heaters (Source: U.S. Energy Information Administration [EIA])	Each heater is 4 kW (residential) or 4.5 kW (commercial). We set the model to look at net load on the grid for a 12-hour period. If net load fell below the lowest 30th percentile of loads, then the storage device would prioritize charging at that time.
COMMERCIAL ELECTRIC WATER HEATERS	$5 per controlled device (Source: technology developer interviews)	310,000 commercial buildings with electric water heaters (Source: EIA)	
ELECTRIC VEHICLE CHARGING	$100 per vehicle (Source: technology developer interviews)	11.5 million vehicles (Source: Bloomberg New Energy Finance)	Each modeled vehicle has a 60 kWh battery and uses a Level 2 charger. In the controlled case, we optimized EV charging to occur at the least-cost hours when the vehicle is parked and plugged in.
RESIDENTIAL SPACE HEAT	$50 per kWh of thermal-electric storage capacity in ceramic blocks (Source: technology developer interviews)	3,700,000 households with heat (Source: EIA)	Each building with electric heating is equipped with one electric thermal system device with 20.25 kWh (residential) or 40 kWh (commercial) of storage. The model simulates the ability to store energy as heat during low-net load periods (e.g., the four lowest hours each day), drawing it down during high-net load periods (e.g., top six hours each day).
COMMERCIAL SPACE HEAT	$50 per kWh of thermal-electric storage capacity in ceramic blocks (Source: technology developer interviews)	240,000 commercial buildings with heat (Source: EIA)	

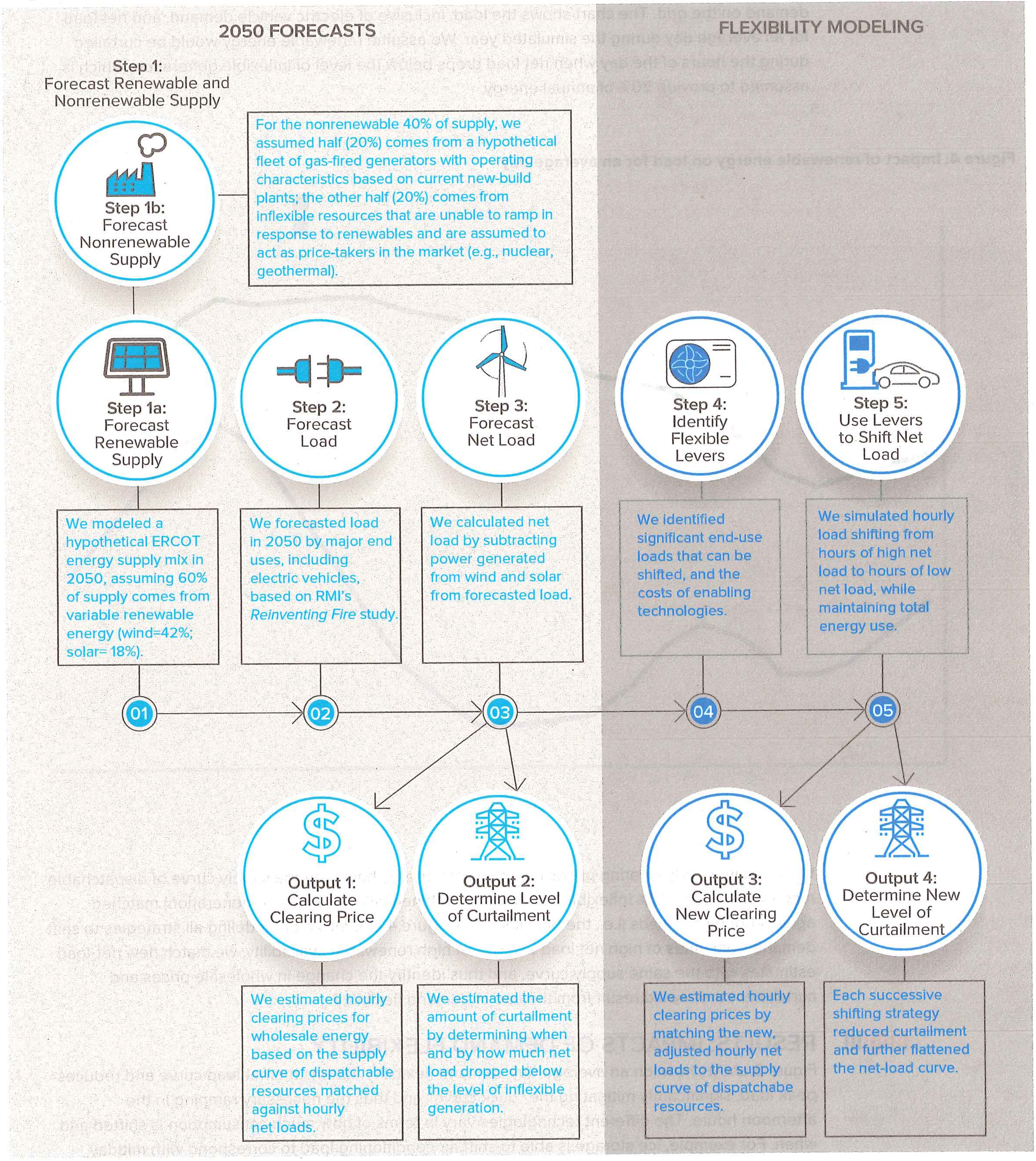
Table 2b: Eight flexible end-use loads used in model

ASSUMED FLEXIBILITY LEVERS	INCREMENTAL COSTS	NUMBER OF FLEXIBLE LOADS MODELED	FLEXIBILITY MODELING ASSUMPTIONS
RESIDENTIAL PLUG LOADS	$10 per household (Source: technology developer interviews)	15,000,000 households (Source: EIA)	We assumed that all Texas households are using "smart" plug load management. We modeled an ability to shift up to 17% of these plug loads by up to 4 hours, based on the estimated contribution and time flexibility of major appliances (e.g., dishwashers, clothes dryers).
RESIDENTIAL COOLING	$228 per kWh of ice storage capacity (Source: technology developer interviews)	3,200,000 households with air conditioning (Source: EIA)	We assumed that each building with air conditioning is equipped with one ice storage unit with 28 kWh (residential) or 57 kWh (commercial) of storage capacity. The model simulates the ability to store energy in ice during low-net load periods (e.g., the seven lowest hours each day), drawing it down during high-net load periods (e.g., top six hours each day).
COMMERCIAL COOLING	$228 per kWh of ice storage capacity (Source: technology developer interviews)	460,000 commercial buildings with air conditioning (Source: EIA)	

RENEWABLE ENERGY AND DEMAND FLEXIBILITY SIMULATIONS

We model a hypothetical 2050 generation mix in ERCOT, using Reinventing Fire outputs to inform the expected contribution of energy efficiency, wind, solar, and other assets to the grid mix. For our base-case scenario in 2050, we used Reinventing Fire's generation forecasts to model hourly renewable energy supply, assuming that 60% of annual generation consists of variable renewable energy (42% from wind and 18% from solar), 20% consists of power from inflexible resources (nuclear, geothermal, etc.), and the remaining 20% consists of natural gas-fired, flexible generation. To estimate net load, we subtracted the power generated from wind and solar from total load for every hour. Figure 3 presents the steps used within our framework.

Figure 3: Framework used to model demand flexibility effect on net load



Step 1: Forecast Renewable and Nonrenewable Supply

Step 1b: Forecast Nonrenewable Supply

For the nonrenewable 40% of supply, we assumed half (20%) comes from a hypothetical fleet of gas-fired generators with operating characteristics based on current new-build plants; the other half (20%) comes from inflexible resources that are unable to ramp in response to renewables and are assumed to act as price-takers in the market (e.g., nuclear, geothermal).

Step 1a: Forecast Renewable Supply

We modeled a hypothetical ERCOT energy supply mix in 2050, assuming 60% of supply comes from variable renewable energy (wind=42%; solar= 18%).

Step 2: Forecast Load

We forecasted load in 2050 by major end uses, including electric vehicles, based on RMI's *Reinventing Fire* study.

Step 3: Forecast Net Load

We calculated net load by subtracting power generated from wind and solar from forecasted load.

Step 4: Identify Flexible Levers

We identified significant end-use loads that can be shifted, and the costs of enabling technologies.

Step 5: Use Levers to Shift Net Load

We simulated hourly load shifting from hours of high net load to hours of low net load, while maintaining total energy use.

Output 1: Calculate Clearing Price

We estimated hourly clearing prices for wholesale energy based on the supply curve of dispatchable resources matched against hourly net loads.

Output 2: Determine Level of Curtailment

We estimated the amount of curtailment by determining when and by how much net load dropped below the level of inflexible generation.

Output 3: Calculate New Clearing Price

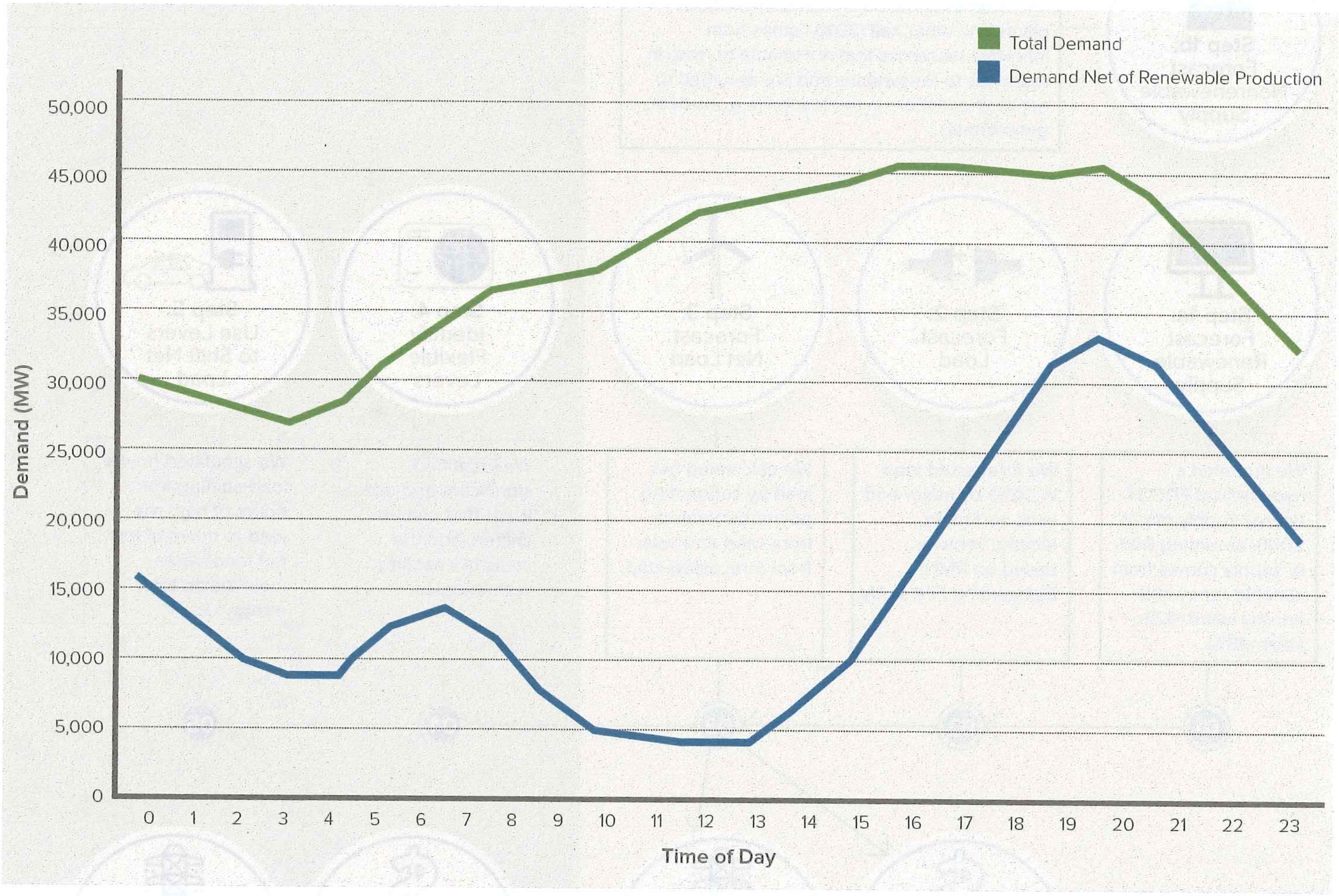
We estimated hourly clearing prices by matching the new, adjusted hourly net loads to the supply curve of dispatchabe resources.

Output 4: Determine New Level of Curtailment

Each successive shifting strategy reduced curtailment and further flattened the net-load curve.

Figure 4 shows how the simulated levels of renewable energy can affect the balance of supply and demand on the grid. The chart shows the load, inclusive of electric vehicle demand, and net load for an average day during the simulated year. We assume renewable energy would be curtailed during the hours of the day when net load drops below the level of inflexible generation, which is assumed to provide 20% of annual energy.

Figure 4: Impact of renewable energy on load for an average day



We estimate hourly clearing prices for wholesale energy based on the supply curve of dispatchable resources (i.e., the 20% inflexible generation combined with 20% flexible generation) matched against hourly net loads (i.e., the blue line from Figure 4 above). After modeling all strategies to shift demand from times of high net load to times of high renewable availability, we match new net-load estimates with the same supply curve, and thus identify the change in wholesale prices and curtailment that would result from the use of demand flexibility.

RESULTS: IMPACTS OF DEMAND FLEXIBILITY

Figure 5 shows how, on an average day, demand flexibility flattens the net load curve and reduces peak load, significantly mitigating the "duck curve" and thus the necessary ramping in the afternoon hours. The different technologies vary in terms of how much consumption is shifted and when. For example, ice storage is able to shift air conditioning load to correspond with midday solar peak and mitigate evening cooling demand. Charging EVs and using plug loads during the middle of the day rather than in the evening significantly reduces the ramping needed during the early evening hours.

Figure 5: Net load and changes from demand flexibility for an average day

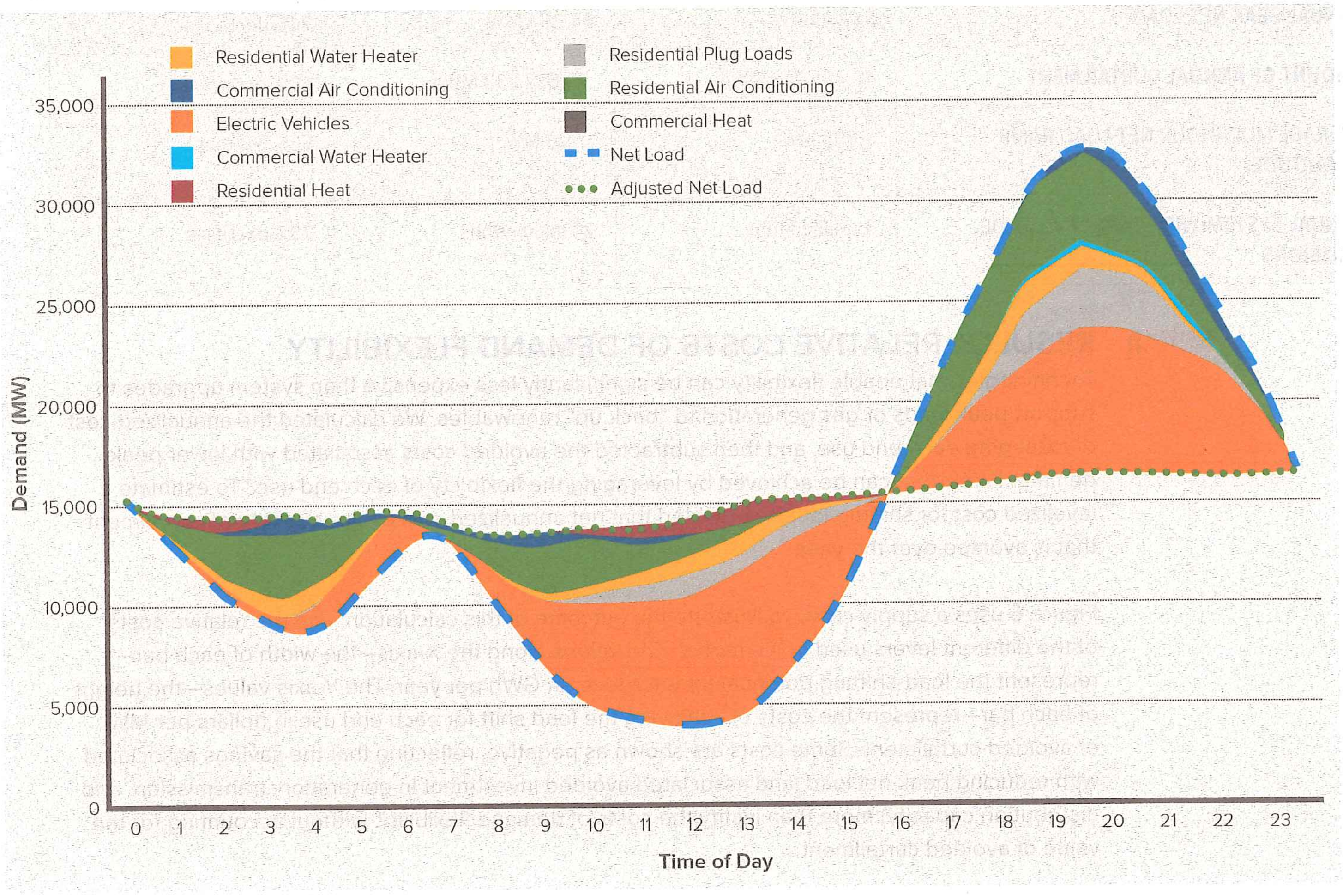


Table 3 summarizes how the introduction of demand flexibility can affect the value of renewable energy, peak loads, curtailment, and ramping. By shifting load to hours of high renewable availability, demand flexibility can significantly increase renewable project revenue, while simultaneously lowering peak net loads, reducing curtailment, minimizing the magnitude of ramping, and cutting CO_2 emissions from gas-fired generation.

Table 3: Summary of modeling results

	WITHOUT FLEXIBILITY	WITH FULL FLEXIBILITY	% CHANGE
AVERAGE ENERGY VALUE OF RENEWABLE GENERATION	$8.70/MWh	$11.82/MWh	36% increase
ANNUAL PEAK NET LOAD	58,441 MW	44,354 MW	24% decrease
AMOUNT OF ANNUAL CURTAILMENT	42,405,742 MWh	25,637,233 MWh	40% decrease
AVERAGE MULTIHOUR NET-LOAD RAMP MAGNITUDE	3,898 MW	1,728 MW	56% decrease
ANNUAL SYSTEM-WIDE CARBON DIOXIDE EMISSIONS	31 million tons	24 million tons	23% decrease

RESULTS: RELATIVE COSTS OF DEMAND FLEXIBILITY

Technologies that enable flexibility can be significantly less expensive than system upgrades to support peak loads or gas generation to "back up" renewables. We calculated the annualized cost of managing each end use, and then subtracted the avoided costs associated with lower peak-demand levels that can be achieved by leveraging the flexibility of each end use.[1] To estimate a levelized cost for shifting load, we divided that net annualized cost by the quantity of curtailment that is avoided over the year.

Figure 6 uses a supply curve to illustrate the outcome of this calculation, and the relative costs of the different levers used in the model. The values along the X-axis—the width of each bar—represent the load-shifting potential for each lever in GWh per year. The Y-axis values—the height of each bar—represent the costs of achieving the load shift for each end use in dollars per MWh of avoided curtailment. Some costs are shown as negative, reflecting that the savings associated with reducing peak net load (and associated avoided investment in generation, transmission, and distribution capacity) more than justify the costs of demand flexibility, without accounting for the value of avoided curtailment.

As shown in Figure 6, commercial space heating, plug loads, EVs, and electric water heaters are inexpensive opportunities to reduce peak net load and renewable energy curtailment. Water heaters, EVs, and plug loads require only a relatively small investment in communications technologies to enable flexibility. Commercial building-space heating requires additional capital investment in dedicated thermal storage capacity, but this incremental cost is more than justified by peak-net load reduction; even after other end uses reduce peak summer net loads in a highly renewable Texas grid, space heating can significantly reduce remaining winter peaks.
We find that enabling significant flexibility from air-conditioning ice storage and residential heating is not as inexpensive as the other loads examined, for several reasons:

1. **Interaction:** To avoid double counting, we simulated the flexibility of these end uses only after the other five end uses were optimized, and thus much of the avoidable curtailment and peak

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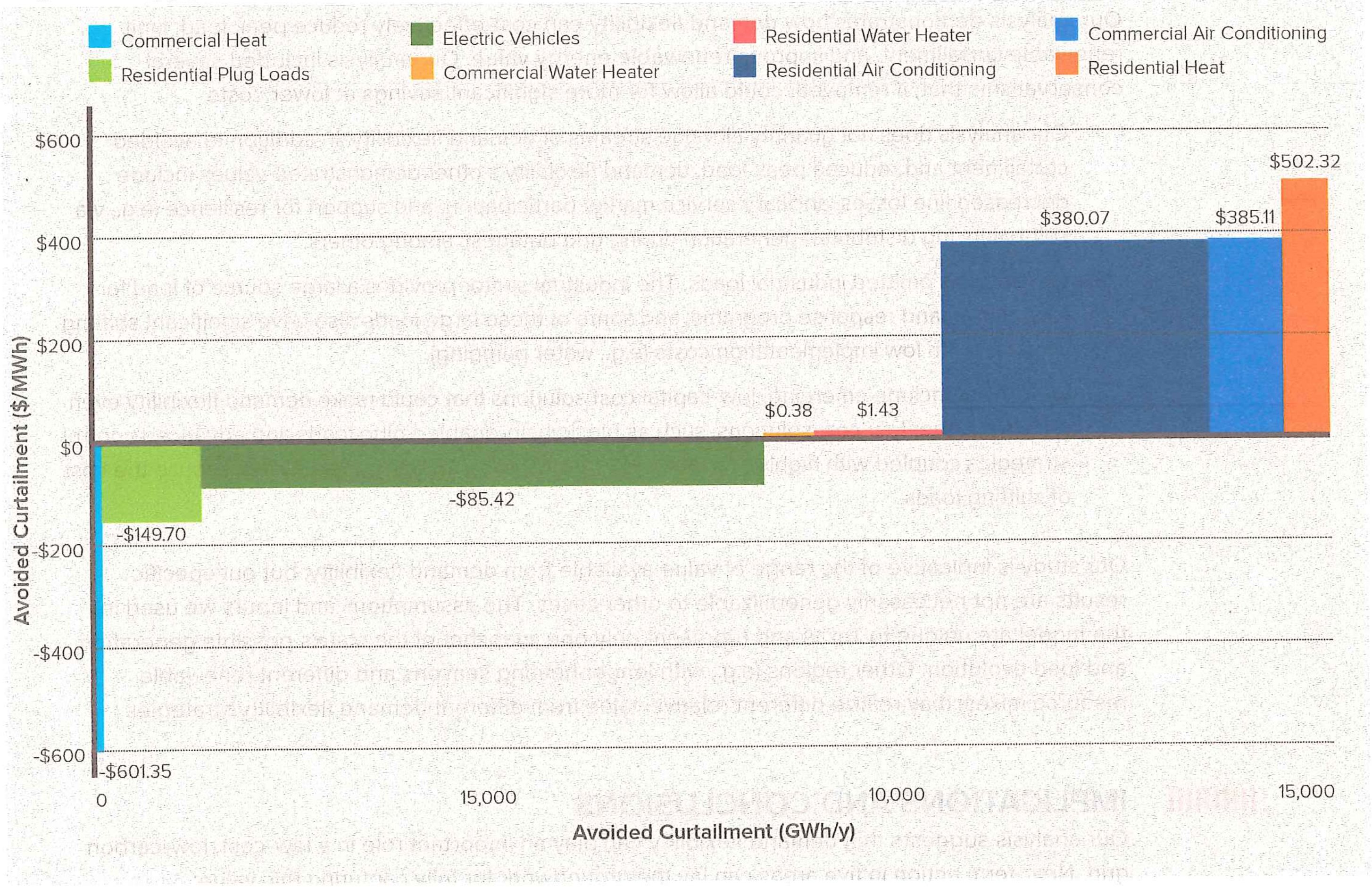
[1] We assumed an avoided cost value of $120/kWy, inclusive of both generation and transmission & distribution avoided costs, based on methodology presented in Appendix A of *The Economics of Demand Flexibility*.

Figure 6: Supply curve of demand flexibility levers



reduction had already been realized; when examined in isolation, the estimated costs for flexibility from these end uses dropped by 30-90%.

2. **Peak coincidence:** Residential loads are not as coincident with simulated peak net load as their commercial counterparts, and in particular, residential space heating occurs almost entirely outside of peak-net load hours (i.e., summer afternoons) in Texas, leading to limited benefits from enabling flexibility in our study geography. Enabling flexibility in these end uses is likely to be cost-effective in different geographies and/or under specific circumstances (e.g., highly congested grid nodes).
3. **Capital intensity:** Thermal storage with ice and/or ceramic blocks requires new capital investment in addition to the energy conversion device itself. However, there are other options for increasing the flexibility of thermal loads, including relying on the thermal mass of the building itself, that are less costly. We conservatively did not assume any ability to use building thermal mass as a buffer to enable demand flexibility for these loads; in our previous demand flexibility analysis at the single-home level, we found that these methods can be very cost-effective.

By combining a portfolio of the demand flexibility strategies modeled, it is possible to achieve approximately 90% of the total benefits of demand flexibility at a net cost savings. This cost-effective portfolio would avoid approximately $1.5 billion per year in annualized generator and transmission & distribution capital costs, $400 million in avoided fuel costs, and 6 million tons per year of CO_2 emissions (i.e., approximately 20% of annual emissions).

CONSERVATISMS AND LIMITATIONS OF THIS ANALYSIS

Our analysis demonstrates how demand flexibility can cost-effectively reduce peak load, limit renewable curtailment, and improve renewable energy value. Our analysis included several conservatisms that, if removed, could allow for more significant savings at lower costs:

- Our analysis does not quantify all value streams of demand flexibility. In addition to avoided curtailment and reduced peak load, demand flexibility's other demonstrated values include decreased line losses, ancillary service market participation, and support for resilience (e.g., via self-balancing distributed generation during grid outages), among others.
- Our analysis omitted industrial loads. The industrial sector provides a large source of load for current demand response programs, and some of these large loads also have significant shifting potential with low implementation costs (e.g., water pumping).
- We did not include emerging, low-capital cost solutions that could make demand flexibility even cheaper. Other low-cost solutions, such as blockchain-enabled plug loads and advanced control strategies coupled with highly efficient, high-thermal mass buildings, can further reduce the cost of shifting loads.

Our study is indicative of the range of value available from demand flexibility, but our specific results are not necessarily generalizable to other cases. The assumptions and inputs we used in the model are unique to Texas and represent only one snapshot of the state's possible generation and load evolution. Other regions (e.g., with longer heating seasons and different renewable resource mixes) may realize different relative value from different demand flexibility strategies.

IMPLICATIONS AND CONCLUSIONS

Our analysis suggests that demand flexibility can play an important role in a low-cost, low-carbon grid. Near-term action in five areas can lay the groundwork for fully capturing this value:

- **Include demand flexibility as a core resource in grid planning to avoid stranded generator investment.** Demand flexibility can avoid significant investment and operational costs that would otherwise be spent on natural gas-fired generation to meet peak loads and balance renewable variability. However, without proactive planning that includes demand flexibility, there is a significant risk of duplicative investment in natural-gas power plants that may become stranded as demand flexibility becomes more cost-effective and commonplace. Utility planners, system operators, and regulators can mitigate this risk by improving planning processes and utilizing software tools that fully reflect the capabilities and value of demand flexibility.
- **Account for demand flexibility when setting targets for highly renewable supply mixes.** Many studies of highly renewable grids find a limit for renewable adoption, above which the marginal value of new renewable resources falls below their investment costs. Our analysis demonstrates that demand flexibility can significantly improve the revenue and system-level value of renewable energy, and suggests that the limit to renewable energy adoption is not fixed, and can rise dramatically if demand flexibility strategies are taken into account during planning and system operation. Policymakers, regulators, and utilities should carefully consider the potential of demand flexibility to help meet renewable energy-adoption targets of 50% and higher across the U.S.
- **Pursue portfolios of renewables and demand flexibility to improve project economics.** In some areas of the U.S, including California and the Midwest, revenues realized by renewable

generation are already falling due to rising renewable adoption, grid congestion, and the inflexibility of other generators. Project developers and/or off-takers thus face price risks, and are increasingly bundling battery energy storage with renewables projects to mitigate exposure and increase value. Our analysis suggests that demand flexibility, as part of a broader resource portfolio, can also address these same price risks. Project developers and utilities should carefully evaluate the economics of resource portfolios composed of renewables and demand flexibility in order to optimize system value.

- **Adjust utility earnings opportunities to encourage noncapital investments.** Traditional cost-of-service regulation rewards utilities for investments in capital they can include in their rate base. However, new regulatory tools, such as performance-based ratemaking, can allow utilities to still earn returns when using lower-cost and/or third party-owned demand flexibility as a grid resource. By addressing the incentives driving the utility business model, policymakers have the opportunity to significantly expand the role of demand flexibility in utility procurement decisions.
- **Create customer incentives to increase flexibility-technology adoption and influence electricity consumption.** The deployment of demand flexibility technologies depends on customer purchasing decisions and willingness to participate in new utility programs. Creating the right incentives, such as rebates or bill savings through time-varying rates, will be key to encouraging customer involvement in demand flexibility programs. Increased use of automation and control technologies and programs that promote participation of aggregated resources can improve the customer experience, providing nonmonetary incentives for customer participation.

Demand flexibility can be an important grid resource in the long run, cost-effectively balancing renewable energy to ease the transition to a low-carbon grid. Near-term action can lay the groundwork for scaled deployment of demand flexibility technologies in a future highly renewable grid, and address the uncertainties around technology costs and performance that are critical to planning for a reliable, low-cost, and low-carbon grid.

RAP® Energy solutions for a changing world

Teaching the "Duck" to Fly

Second Edition

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Cover image by Tim Newcomb

Teaching the "Duck" to Fly

Second Edition

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Acronyms

GIWH	Grid-integrated water heating	**MW**	Megawatt
ISO	Independent system operator	**PV**	Photovoltaic
ISO-NE	New England Independent System Operator	**TOU**	Time-of-use
kWh	Kilowatt-hour	**UPS**	Uninterruptible power supplies

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Foreword to the Second Edition

The First Edition of *Teaching the "Duck" to Fly,* released by The Regulatory Assistance Project (RAP) in January 2014, posed an integrated approach to the way utilities and regulators examine the challenge of adapting to a power system with significant variable renewable resources. Prior to that time, the focus of most analysts was simply on the strained flexibility of the remaining fossil generation fleet, and the need to add flexible generation and electricity storage resources, both of which have high costs. *Teaching the "Duck" to Fly* changed this, by focusing at least equal attention on the flexibility that customer loads, low-cost thermal storage, time-varying pricing, and other simple strategies could provide in adapting to a two-way system, relying equally on supply-side and customer load management.

The First Edition was presented at meetings of US regulators, at the Florence (Italy) School of Regulation, and to utilities and their regulators in China, India, the Middle East, Africa, and Australia. It was the subject of a series of webinars, attracting a global audience. Feedback from these varied audiences was considerable, and the author, RAP as an organization, and indeed the entire industry have learned more in the intervening two years. Here are a few lessons we take away from this experience.

Some of the concepts in the First Edition proved to be of limited value. For example, concentrated solar power has not been well received in the market, mostly because of the dramatic drop in the cost of solar photovoltaic (PV) generation. West-facing solar is important where it is achievable, but the benefits are modest. In this Second Edition, these are consolidated into a strategy for "peak-oriented renewables," that include wind sites with favorable production characteristics and more disciplined use of existing hydroelectric resources.

However, the First Edition also dramatically understated the potential of **water heating** and **air conditioning** storage technologies. These technologies have evolved quickly in recent years, and the economics are becoming more favorable. Dozens of pilot programs for grid-integrated water heating have proven this concept and will soon be deployed in many regions. The number of ice storage and chilled-water storage air conditioning systems has grown, but still reaches less than two percent of the potential market. The Second Edition makes greater use of these highly reliable, low-cost resources to further smooth the utility load profile.

A new strategy has been introduced in the Second Edition: control of **water and wastewater pumping**. These uses consume about seven percent of total US electricity. Water is very easy to store in tanks, reservoirs, and aquifers. In many cases, all that is needed to stimulate management of these loads is a restructuring of the electricity pricing to remove demand charges and substitute time-varying energy charges. The potential can be even greater if water and wastewater utility planning is conducted interactively within electricity least-cost planning, so that, for example, increased water storage capacity can become a substitute for increased electricity generation capacity.

As in the original edition, the Second Edition starts with the load shape of an illustrative California utility, before and after addition of significant solar and wind resources. It then incrementally includes each of the strategies to produce a gradual change in the load shape. The "bottom line" of this Second Edition is a package of measures that, conservatively estimated but aggressively deployed, can dramatically reshape the electricity load that must be served by dispatchable resources. The "ending load factor" after the ten strategies is an impressive 86.5 percent, far higher than what exists today. Simply stated, it should be easy to adapt to the "Duck Curve" that emerges as variable renewables are installed on utility grids around the world.

Finally, the author wants to thank a few of the many people and organizations who helped examine, critique, and test the concepts proposed in the First Edition. These people have enhanced those ideas, tested them on real utilities and real utility customers, and helped make the

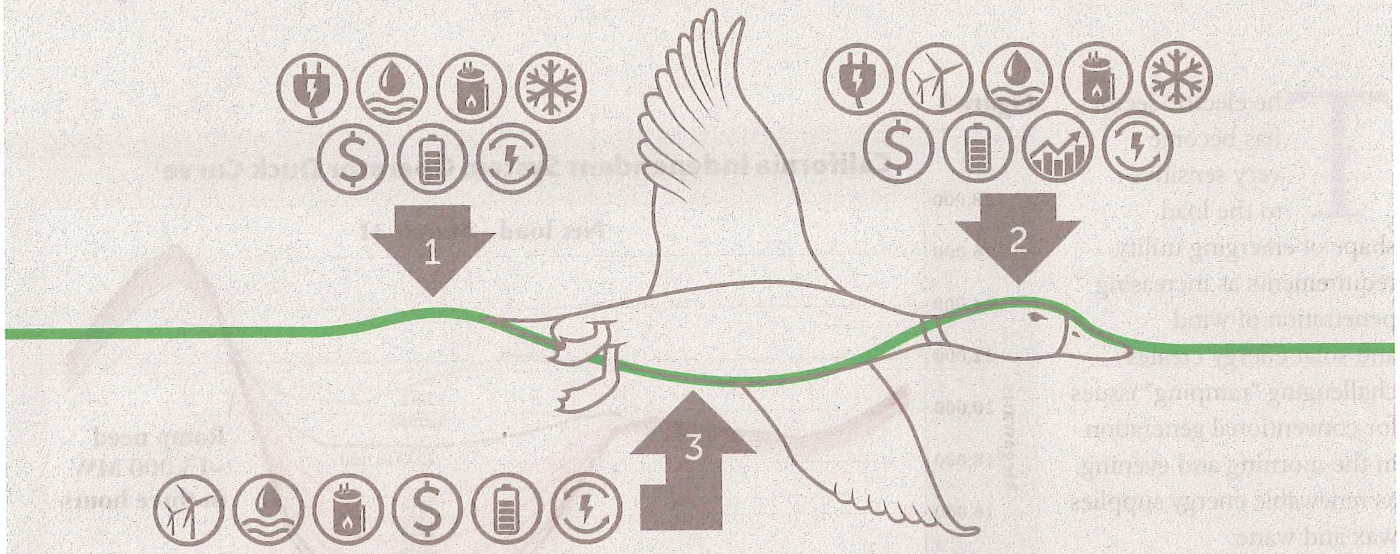
Second Edition a much better product. These include:

- Burbank Water and Power, and its General Manager Ron Davis, for quickly putting some of the concepts from the First Edition to a reality test in California as that utility expands from less than five percent renewables in 2010 to 50 percent renewables by 2030, including the strategies relating to water pumping, west-facing solar, air conditioning storage, rate design reform, inter-region power trading, and time-varying pricing for electric vehicle charging loads;
- The Hawaii Public Utilities Commission, Hawaiian Electric Company, Kauai Island Utility Cooperative, and Hawaii Energy, for embracing the concepts of *Teaching the "Duck" to Fly* and quickly expanding the state of the science in a very dynamic and challenging electricity market;
- Steffes Corporation, Great River Energy, and the Peak Load Management Association, for advancing the state of the science for water heater controls, one of the two most important emerging strategies in this paper;
- Calmac Corporation and Ice Energy, for assistance understanding the technology and economics of air conditioning storage, the other of the two most important emerging strategies;
- The Northwest Power and Conservation Council, for a 30-year disciplined approach to evaluating energy efficiency options, including the peak load value of different energy efficiency measures that makes Strategy 1 a well-recognized option; and
- Finally, my many RAP colleagues who contributed to the original concept, and have helped expand my own knowledge to make this Second Edition possible. Stimulated by our founder, David Moskovitz, to continually challenge skepticism and to hatch and promote "Big Ideas" that can change the world, RAP is an incredible group of smart, creative people. It is a joy to work with them. Visit *About RAP* on the RAP website to meet all of these amazing people.

Jim Lazar
Olympia, Washington
January 2016

Teaching the "Duck" to Fly:

10 strategies to control generation, manage demand, & flatten the Duck Curve



Targeted Efficiency
Focus energy efficiency measures to provide savings in key hours of system stress. ⬇1 ⬇2

Peak-Oriented Renewables
Add renewables with favorable hourly production. Modify the dispatch protocol for existing hydro with multi-hour "pondage." ⬇2 ⬆3

Manage Water Pumping
Run pumps during periods of low load or high solar output, curtailing during ramping hours. ⬇1 ⬇2 ⬆3

Control Electric Water Heaters
Increase usage during night & mid-day hours, & decrease during peak demand periods. ⬇1 ⬇2 ⬆3

Ice Storage for Commercial AC
Convert commercial AC to ice or chilled-water storage operated during non-ramping hours. ⬇1 ⬇2

Rate Design
Focus pricing on crucial hours. Replace flat rates & demand charge rate forms with time-of-use rates. Avoid high fixed charges. ⬇1 ⬇2 ⬆3

Targeted Electric Storage
Deploy storage to reduce need for transmission & distribution, & to enable intermittent renewables. ⬇1 ⬇2 ⬆3

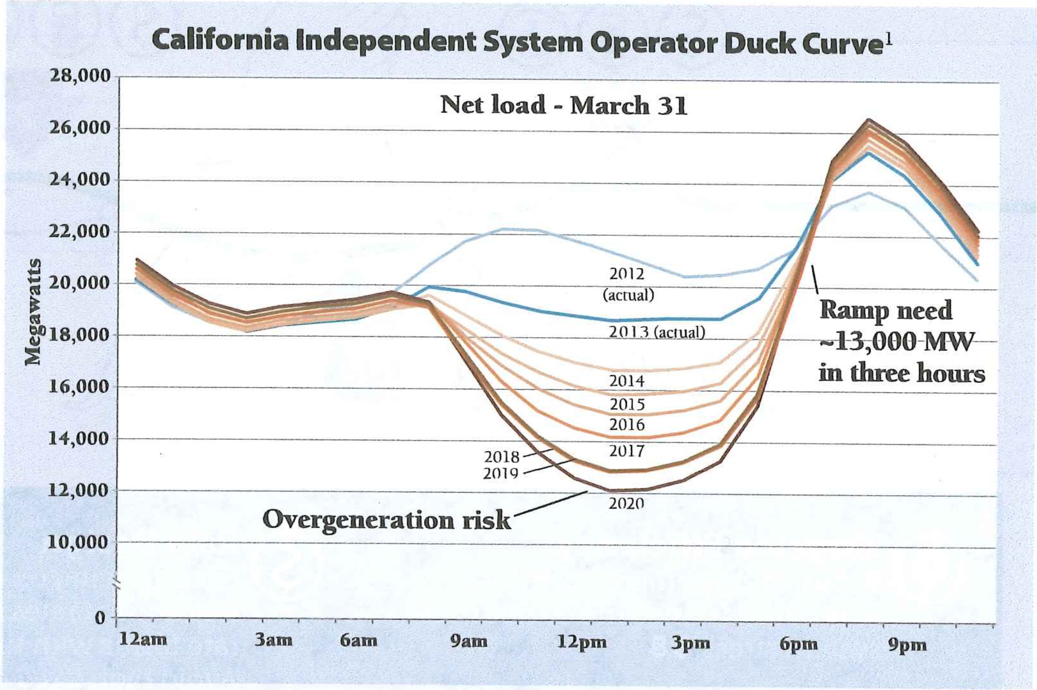
Demand Response
Deploy demand response programs that shave load during critical hours on severe stress days. ⬇2

Inter-Regional Power Exchange
Import power from & export power to other regions with different peaking periods. ⬇1 ⬇2 ⬆3

Retire Inflexible Generating Plants
Replace older fossil & nuclear plants with a mix of renewables, flexible resources, & storage.

Introduction: Teaching the "Duck" to Fly

Figure 1



The electric sector has become very sensitive to the load shape of emerging utility requirements as increasing penetration of wind and solar energy creates challenging "ramping" issues for conventional generation in the morning and evening, as renewable energy supplies wax and wane.

Fundamentally, this issue is no different from the problem utilities have addressed for over a century: adapting the supply of energy to match changing consumer demand. The difference is that daily and seasonal usage patterns and the resources that have historically served that pattern have evolved gradually over the last 125 years, whereas the renewable energy revolution is creating new challenges in a much shorter period of time.

Addressing this problem will require a change in the way utility power supply portfolios are formulated, but solutions are at hand. Fortunately, we have technologies available to us that our great-grandparents did not.

Previously, the utility's role was to procure a least-cost mix of baseload, intermediate, and peaking power plants to serve a predictable load shape. Today, utilities have to balance a combination of variable generation power sources, both central and distributed, together with dispatchable power sources, to meet a load that will be subject to influence and control through a combination of policies, pricing options, and programmatic offerings. This now includes the capability to dispatch customer loads, including water heating, air conditioning, and water pumping, strategies at the heart of this paper.

What is now being referred to as "the Duck Curve" (Figure 1) is a depiction of this emerging change that has become commonly recognized throughout the electric sector. Over time, as more solar and wind energy are added to the grid, the "net load" to be serviced from dispatchable resources (the duck's belly) sags in the middle of the solar day when solar generation is highest, but the load to be served in the early evening after the sun goes down continues to grow (the head) and the transition between the two gets more severe (the neck).

This paper attempts to model the options for a hypothetical, illustrative electric utility facing its own duck curve. Our illustrative utility is expected to add 600 megawatts (MW) of distributed solar, 1,250 MW of utility-scale solar, and 725 MW of wind capacity in response to a state

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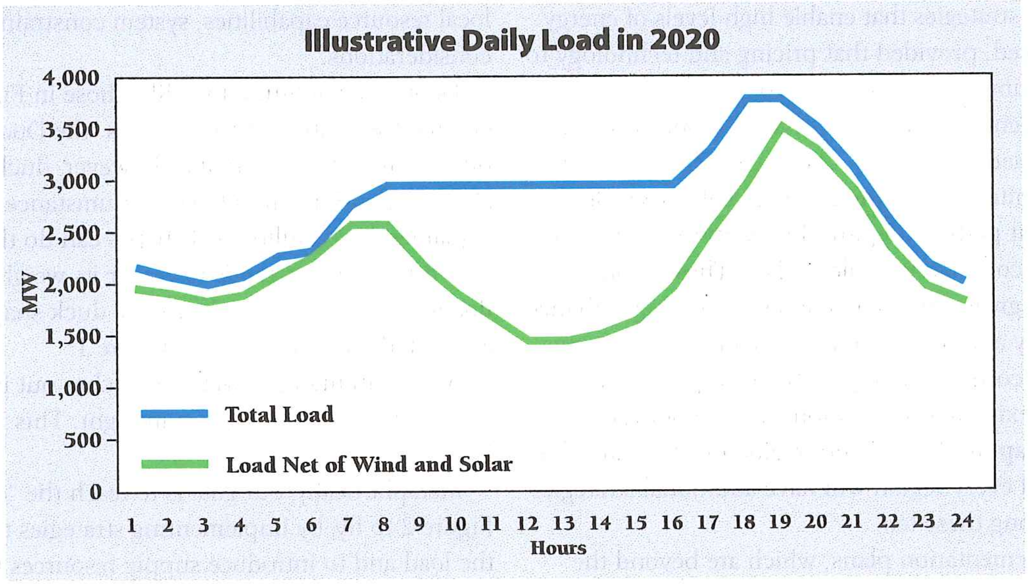
[1] California ISO. (2013). What the duck curve tells us about managing a green grid.

Figure 2



renewable portfolio standard by the year 2020. Figure 2 illustrates an hourly demand and net demand (net of solar and wind) analysis for this utility on a sample day, before any of the options are considered.[2]

The total load line in Figure 2 shows the utility's projected total load, by hour, during the day. The "load net of wind and solar" line shows the load that the utility will face after expected wind and solar generation serve a portion of the total load. Figure 2 shows that the overall load has a moderate diurnal shape, but when the wind and solar energy expected by 2020 are added to the mix, the ramping down of conventional supply in the morning (as solar generation increases) and rapid ramping up in the afternoon hours (as loads increase but solar energy supplies drop off quickly) is even more sharp, creating operational concerns for the utility. This "net load" to be served by conventional dispatchable generating resources must be met with the existing or emerging generation fleet. This challenge is causing some utilities to assert that the proportion of energy needs met by variable generation resources needs to be limited. Although some utilities may argue that variable renewable energy can be relied on

Figure 3

Duck Sitting in Water

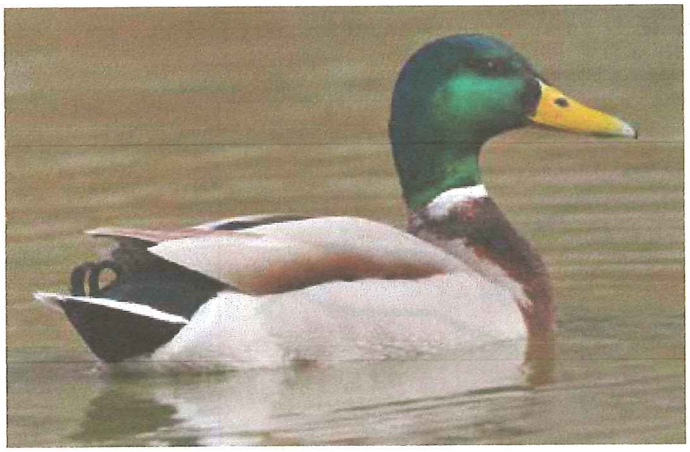


Figure 4

Duck in Flight

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[2] It should be noted that this illustrative day is a light load: a heavy renewable energy generation day such as one that might be experienced in the spring or fall. It is not intended to represent a "normal" or "summer peak" day. It is selected to illustrate the opportunities available to meet a particularly challenging situation.

only for a small portion of daily energy requirements, this paper discusses strategies that enable high levels of energy needs to be served, provided that pricing and technology to increase the flexibility of loads are employed.

This paper identifies a number of low-carbon strategies that can be applied to meet this challenge. These strategies are generally limited to existing commercially available technologies, but perhaps deployed in ways that have not been done on a commercial scale to date. These strategies not only enable greater renewable integration, they enhance system reliability and reduce generation and transmission capital and fuel costs by modifying the load profiles and better utilizing existing transmission assets. Not every strategy will be applicable to every region or utility around the country, and every region will have additional strategies that are not among these ten.

Specific implementation plans, which are beyond the scope of this paper, will need to be tailored to address local resource capabilities, system constraints, and other considerations.

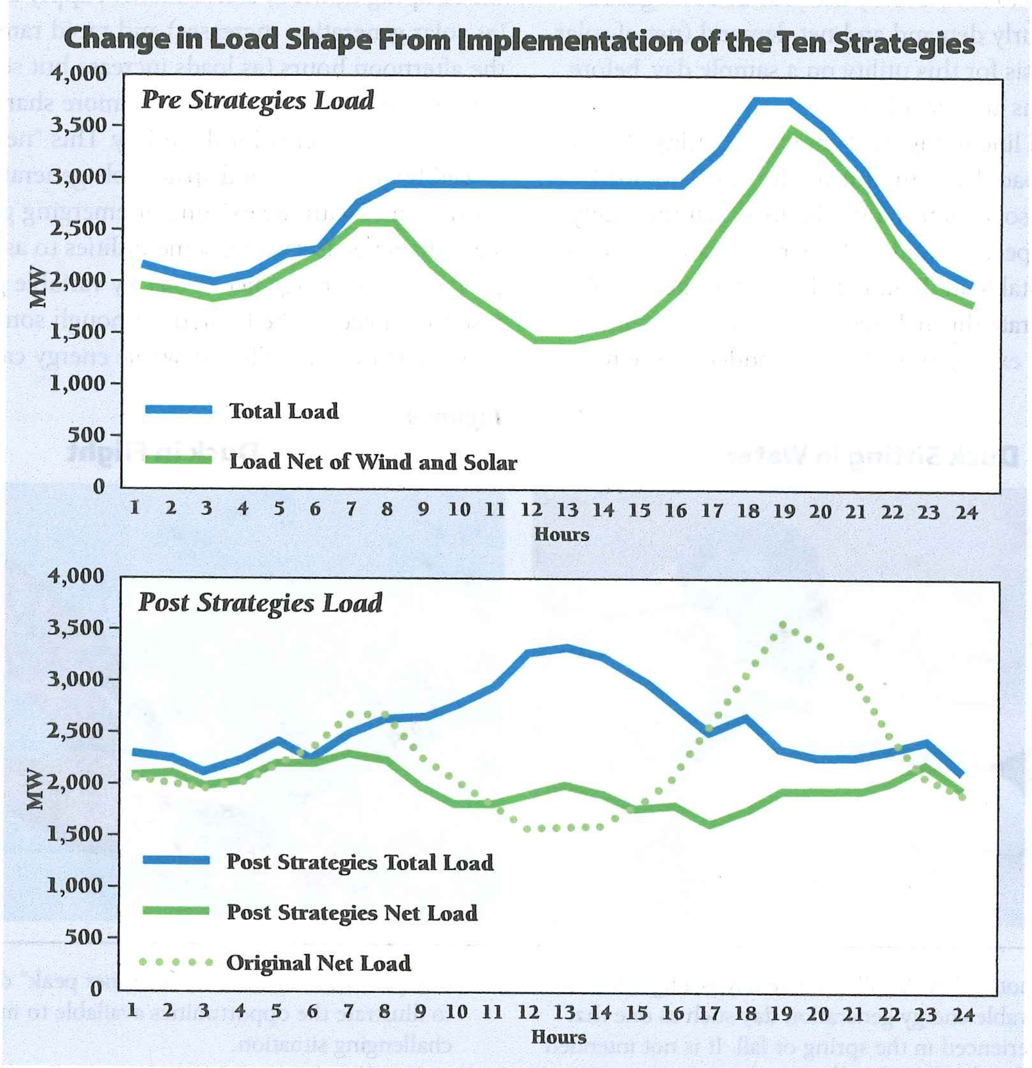
Depictions of future load like those in Figure 1 have entered the industry vernacular as "the Duck Curve" for obvious reasons. In actuality, however, ducks vary their shape depending on different circumstances, and as explained here, utility load shapes can do the same.

A duck in water tends to center its weight in the water, floating easily. Figure 3 shows the duck shape commonly associated with the graph in Figure 1.

A duck in flight, however, stretches out its profile to create lower wind resistance in flight. This is illustrated in Figure 4.

Metaphorically, our goal is to teach the "duck" in Figure 2 to fly, by implementing strategies to both flatten the load and to introduce supply resources that can deliver

Figure 5



more output during the late afternoon high load hours. Many of these strategies are already used on a modest scale in the United States and European Union, whereas others use technologies that have been proven in pilot programs but are not yet deployed on a commercial scale. None require new technology and each has a small (or negative) carbon footprint.

Figure 5 shows the change in shape of the Duck Curve from the cumulative application of the ten strategies we propose below. Like an actual duck, it becomes more streamlined and better able to "take flight."

We include the following ten strategies in our analysis:

Strategy 1. Target energy efficiency to the hours when load ramps up sharply;

Strategy 2. Acquire and deploy peak-oriented renewable resources (Strategies 2 and 3 in the original paper);

Strategy 3. Manage water and wastewater pumping loads (new in the Second Edition);

Strategy 4. Control electric water heaters to reduce peak demand and increase load at strategic hours;

Strategy 5. Convert commercial air conditioning to ice storage or chilled-water storage (greatly increased in magnitude in the Second Edition);

Strategy 6. Rate design: focus utility prices on the "ramping hours" to enable price-induced changes in load;

Strategy 7. Deploy electrical energy storage in targeted locations;

Strategy 8. Implement aggressive demand-response programs;

Strategy 9. Use inter-regional power exchanges to take advantage of diversity in loads and resources;[3] and

Strategy 10. Retire inflexible generating plants with high off-peak must-run requirements.

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[3] For a complete set of regional strategies consistent with this step, see: Schwartz, L., Porter, K., Mudd, C., Fink, S., Rogers, J., Hogan, M., Lamont, D., & Kirby, B. (2012). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge.* Western Governors' Association.

Strategy 1:

Target Energy Efficiency to the Hours When Load Ramps Up Sharply

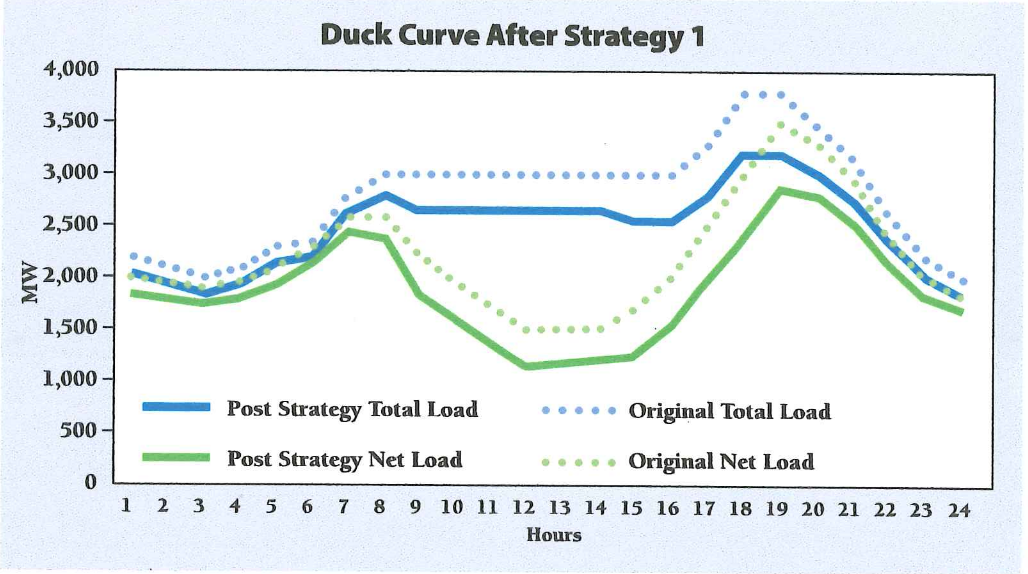
Strategy Description:

Acquire energy efficiency measures with a focus on measures that provide savings in key hours of system stress.

Amount:

11 percent of total system load, with a 4:1 ratio of on-peak to off-peak consumption (compared to a 3:1 ratio for overall load).

Figure 6

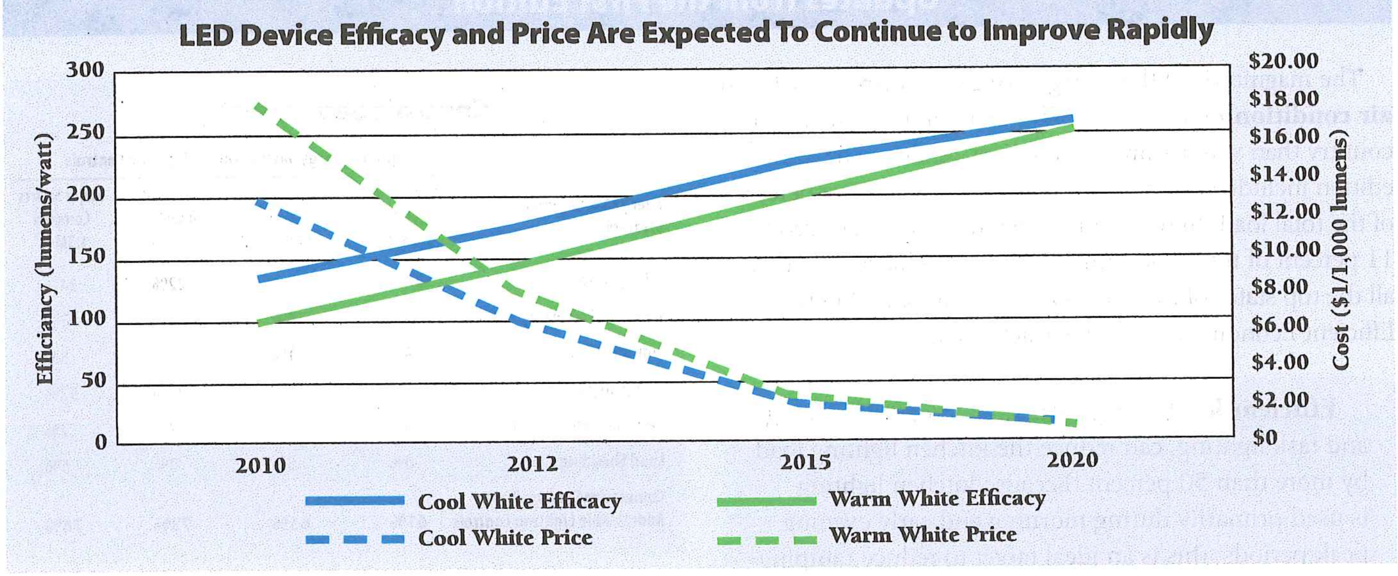


The rapid increase in loads to be served from dispatchable resources between 4 PM and 7 PM that dominates the Duck Curve is made up of discrete elements of electricity usage primarily in the residential and commercial sectors. It is a period when office building loads continue, while residential loads increase as residents return from school and work. People come home, turn on televisions, start cooking, and, in the winter, use significant amounts of lighting. This late-afternoon convergence of residential and commercial loads causes system peaks on most utility systems.

Overall, energy efficiency has about the same shape as the system load, with contributions to peak load reduction about twice as great as the impact during off-peak hours. But many measures are available that have a higher level of peak-orientation. We address three of these: residential lighting, air conditioning, and office building lighting controls.

Residential lighting, particularly kitchen-area lighting, is concentrated around morning and evening peak periods. Higher-efficiency LED lighting is quickly becoming inexpensive, reliable, and of increasing efficacy. By 2020, efficacy (light output per watt of energy input) is forecast to be three times that of current CFL lamps. Thus, the

Figure 7



residential lighting load, already cut in half with CFL programs over the past decade, can be cut in half again with LED retrofits. The reduction in afternoon lighting also brings with it a reduction in residential air conditioning requirements, because less energy is released as heat.

Figure 7 shows the expected improvement in LED lighting efficiency and reduction in LED lighting cost over this decade. This suggests that even LED to LED replacement of early-vintage LED lighting may be cost-effective to reduce late afternoon peak usage.

Street lighting is unique in that it is *only* used during hours of darkness, beginning with the early-evening ramping hours. LED street lights can achieve a 30- to 70-percent reduction in ramping period lighting needs.

Lighting in the retail sector is another area in which efficiency opportunities are considerable, but because that sector uses light throughout the day and into the evening, this efficiency will reduce not only peak demands that cause a ramping need, but also mid-day demands that support minimum-level operations for power plants needed during the ramping period. Although the energy savings are significant, the ramping benefits may be small.

The office lighting sector presents a different opportunity. Workers in office buildings generally depart the office between 4 PM and 6 PM, depending on their starting time and work load. Often entire floors remain lit until the last worker has departed. Modern building energy management systems can control lighting so that smaller zones are controlled, providing adequate light for remaining workers, and zoned lighting during custodial work, without needing to light entire floors. As much as one-half of office lighting loads can be curtailed during the 5 PM to 8 PM ramping hours without significant adverse impacts on building users.

High-efficiency residential air conditioners are an exemplary opportunity, because of the great opportunity to improve efficiency and the high peak-concentration of this load. These loads represent approximately ten percent of total residential sales, but up to 70 percent of residential peak demands. Simple measures, such as Energy Star® replacements of window and central air conditioners can produce 30- to 50-percent reductions in this load. More expensive alternatives, including ground-source heat pumps, can produce 60- to 80-percent reductions in this load. Ice storage and chilled-water storage air conditioning are discussed in Strategy 3, for commercial and institutional buildings, but are not considered commercially available for residential-scale applications.

Strategy 1 assumes that the illustrative utility can reduce its peak load by 16 percent, and off-peak loads by one-half that amount, with efficiency programs that target peak and ramping period loads. Figure 6 shows the effect of this strategy on the loads of the illustrative utility.

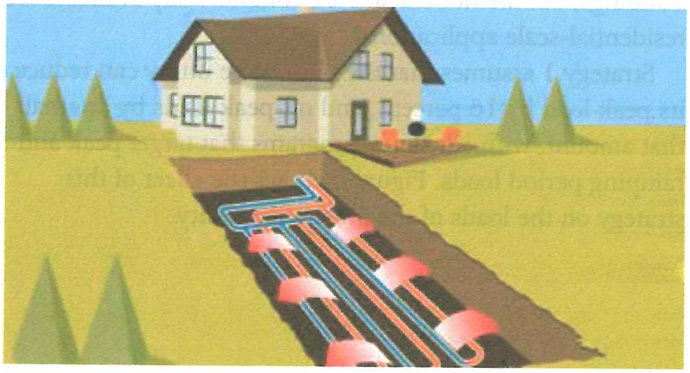
Updates from the First Edition

The magnitude of the **energy efficiency opportunity for air conditioning** is dramatically greater in most areas of the country than was assumed in the First Edition. The previous edition included energy efficiency equal to only five percent of the total load. In this edition, that has been increased to 11 percent of total load. This is a level of achievement that all the top states of the American Council for an Energy-Efficient Economy ratings[4] have achieved.

Efficient kitchen lighting, including LED ceiling and task lighting, can reduce the kitchen lighting load by more than 50 percent. Because kitchen lighting is used primarily during morning and early evening peak periods, this is an ideal target to reduce ramping requirements resulting from high solar deployment.

Ground source heat pumps are up to five times as efficient as other heating and cooling systems, because they rely on a stable underground temperature geothermal resource.

These can dramatically reduce afternoon cooling needs—and winter heating requirements, when replacing conventional electric heat.



Source: ClimateMaster, Inc.

Controls Save Energy

	Lighting Energy Savings Due to Lighting Controls			
Energy Management Strategies	**Multi-tenant Office Bldg 300K ft²**	**Corporate Office Bldg 400K ft²**	**Hospital Admin Bldg 175K ft²**	**Major Sports Complex 1.3M ft²**
Adaptive Scheduling	14%	9%	22%	24%
Daylight Harvesting	1%	4%	8%	3%
Lighting Limits	9%	11%	13%	5%
Occupancy Control	31%	25%	25%	37%
Personal Task Control	6%	11%	2%	2%
Load Shedding	0%	5%	3%	5%
Cumulative Savings Due to Addressable Lighting Controls	61%	65%	73%	76%

Commercial building lighting controls can produce immense overall savings.

Office buildings are a key target for this strategy, because office *occupancy* drops off at the time of the late afternoon ramping period, but office lighting often remains on until the last workers leave and janitorial tasks are completed. Zoned lighting controls can preserve lighting for those still working, while reducing total building usage by up to two-thirds.

Line losses are highest during peak hours, because they increase exponentially with the demand on the distribution system.[5] Most of the strategies in this paper are directed at reducing peak loads, and energy efficiency is Strategy 1. Reducing peak loads can sharply reduce line losses.

Source: Flickr, Bob Mullica

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[4] Massachusetts, Rhode Island, California, Oregon, Connecticut, Vermont, New York, Washington, Illinois, Minnesota, and Maryland. Retrieved from http://aceee.org/state-policy/scorecard.

[5] Lazar, J., & Baldwin, X. (2011). *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*. Montpelier, VT: The Regulatory Assistance Project.

Strategy 2:
Acquire and Deploy Peak-Oriented Renewable Resources

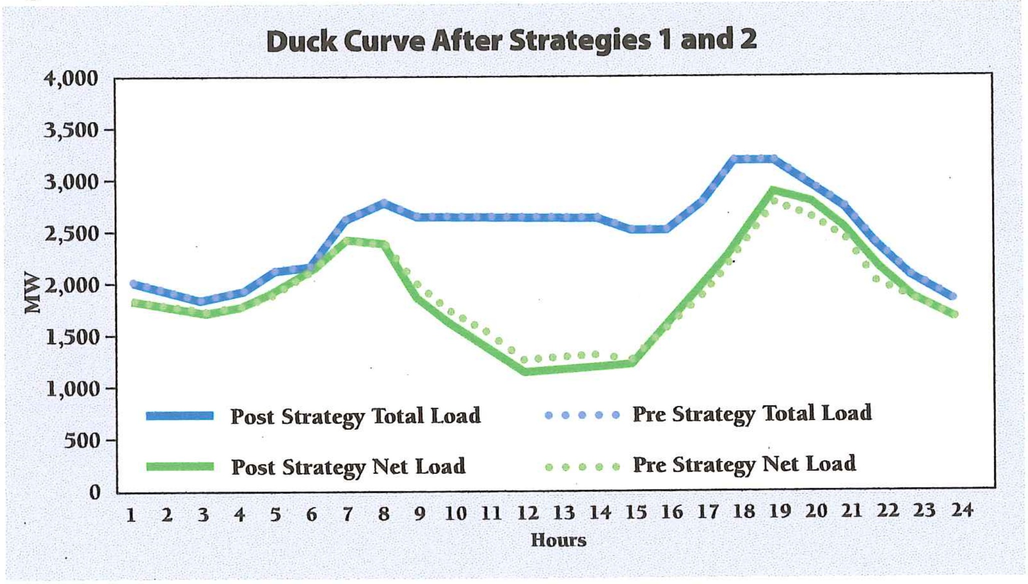
Strategy Description:

Acquire wind, solar, or hydro resources that have favorable hourly production. Modify the dispatch protocol for existing hydro resources with multi-hour pondage.

Amount:

Substitution of anticipated renewable portfolio with 100 MW of solar PV oriented to the west; 100 MW of solar in the form of solar thermal with 3-hour storage capacity; 100 MW of wind with late afternoon/early evening concentration of output.

Figure 8



Many utilities have acquired renewable energy from wind and solar facilities to comply with state renewable portfolio standards. These standards typically apply to an annual obligation and do not differentiate between times when the renewable energy is produced. We have learned that timing does matter. Fortunately, there are many renewable resources that produce energy at favorable times of the day, or can be controlled or modified to do so.

These options include:

Storage Hydro Facilities. Most hydro facilities have lakes or at least "pondage" where the water is stored before flowing through turbines to produce power. These projects allow the utility to produce power when it is most valuable, and, in many cases, utilities have installed additional turbines on dams to increase their hydro potential. The largest example of this is the Third Powerhouse at Grand Coulee Dam, which adds 4,500 MW of peaking capacity but involves no additional storage, and adds little in the way of additional annual energy production. There are some facilities that are strictly run-of-river or purely as-available, and those do not offer any flexibility. In addition, some hydro projects are subject to fish, irrigation, navigation, flood control, and other operating conditions that may limit productivity.

Wind Site With Favorable Characteristics. Wind energy sites are normally developed only after extensive monitoring of wind conditions. Some locations are most productive in the night-time hours, and others in day-time hours. Seeking sites with favorable late afternoon production can provide a favorable resource addition to the utility system.

West-Facing Solar Panels. These produce power up to two hours later in the afternoon than south-facing panels do, but produce fewer annual kilowatt-hours (kWh). Without time-differentiation in compensation, solar system owners will choose the easiest installation with the most annual kWh. Time-varying prices will induce these producers to install tracking systems or west-facing panels to increase generation during the ramping hours when generation may be most valuable.

Solar/Thermal. These power plants gather sunlight and concentrate it to heat water or another fluid that drives a conventional turbine to produce electricity. Storage of the heated fluid allows for production of electricity several hours after the sun has set, producing a more valuable product.

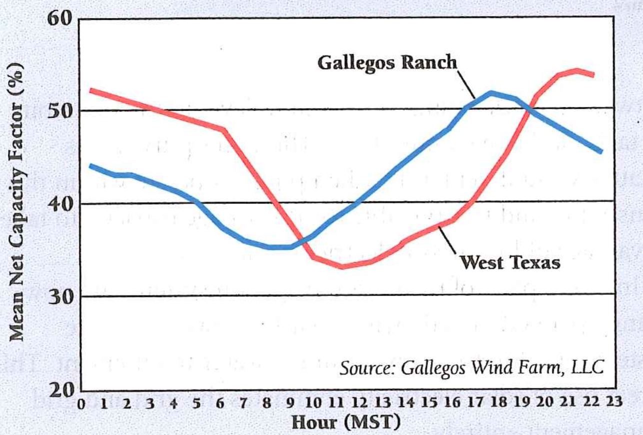
Figure 8 shows the load shape for our illustrative utility if 100 MW of solar facilities were west-facing, if 100 MW of solar-thermal with storage were installed instead of PV, and if 100 MW of wind energy with favorable afternoon production were selected. We have not included any redispatch of hydro resources, as that option is only available to utilities with flexible hydro generation in their fleet.

Updates from the First Edition

Hoover Dam and many other hydro facilities, particularly in the western states, typically have only enough water to operate the turbines a few hours per day. By **scheduling that operation in the ramping hours**, the utilities receiving this power can both receive a carbon-free resource and use that resource to better integrate variable wind and solar resources.

Some wind projects have **favorable afternoon production patterns.** This graph compares the expected production from the Gallegos Wind Farm in New Mexico, where production peaks closer to 7 PM in the evening, to the typical wind pattern found in West Texas, where electricity peak production is closer to 10 PM.

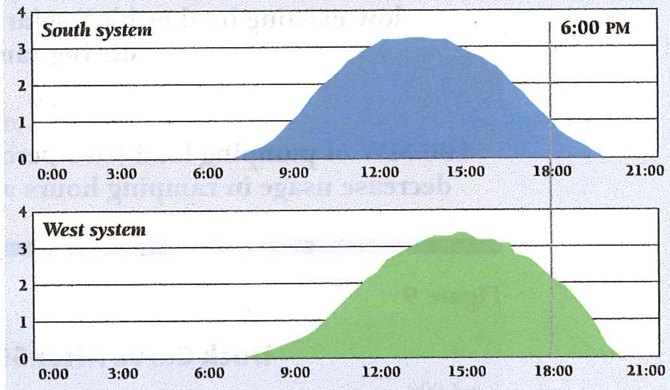
Annual 80-m Diurnal Wind Energy Patterns



Source: Gallegos Wind Farm, LLC

Additional research may identify other projects with favorable patterns. Additional interconnections between Texas and other grids may enable higher levels of wind production in all areas.

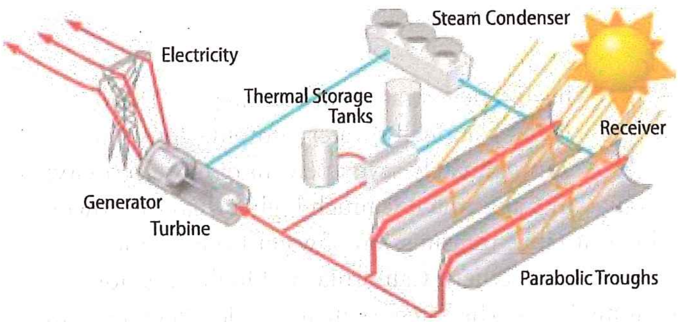
Average daily generation profile (kW) from rooftop PV systems for south and west systems



Source: Pecan Street Research Institute. (2013). South-facing solar cut peak demand from grid 54% - west-facing systems 65%.

This figure demonstrates that west-facing PV projects produce useful output up to two hours longer in the evening, when the most serious ramping challenges are experienced.

Using **solar-thermal generators** in place of PV systems provides the opportunity to store solar energy in the form of superheated fluids or salts, allowing generation to occur hours after the solar energy has been gathered.



Source: EcoMENA. (2015). CSP-Powered Desalination Prospects in MENA

Strategy 3:
Manage Water and Wastewater Pumping Loads

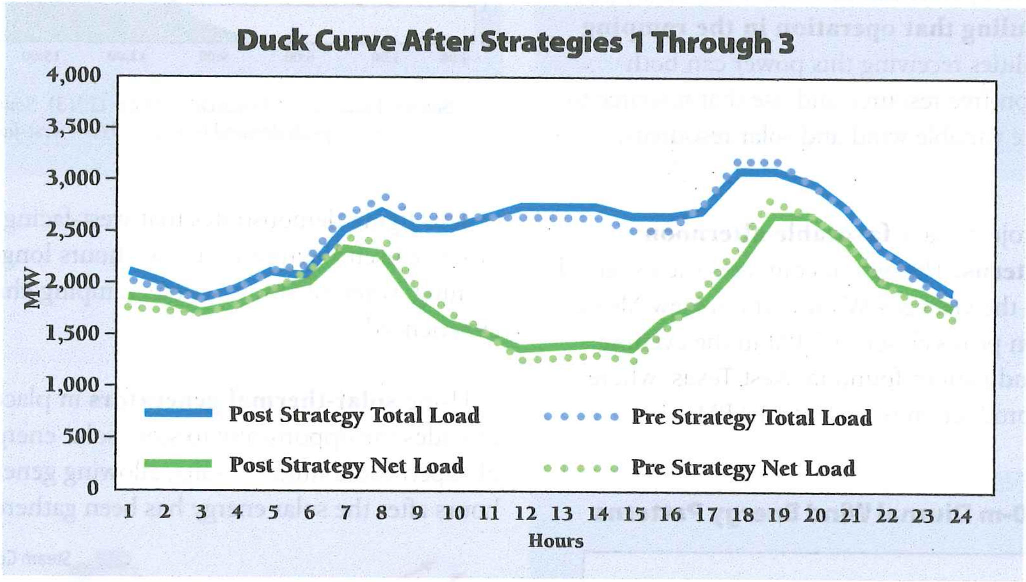
Strategy Description:

Control water and wastewater pumps to operate during periods of low existing load or high solar output, curtailing pumping load during ramping hours.

Amount:

100 MW of pumping load (two percent of total system load) controlled to decrease usage in ramping hours and increase usage in off-peak hours.

Figure 9



This is a new strategy in *Teaching the "Duck" to Fly*. Nationally, water pumping consumes approximately seven percent of our electricity; in California it is much higher than this, owing to long-distance transmission of water from northern California to southern California, and high irrigation pumping loads. The category includes electricity used for water well production, water transmission, irrigation, water treatment, water distribution, and wastewater treatment.

Water pumping is a unique opportunity to shift load, because water is a physical good that can be stored in water tanks and reservoirs. Most water system pumps operate between two set-points: a minimum level in the reservoir or tank, and a maximum level. The water purveyor is relatively indifferent as to when pumps operate within this constraint, and it is possible to add storage capacity to take advantage of lower-cost electricity prices.

In many parts of the world, irrigation systems are now being operated directly with solar PV power, with the systems sized to the daily pumping water requirement. This direct use of solar electricity eliminates the grid and grid management entirely.

Most utilities have demand-charge rate designs that impose a significant charge based on the highest level

Table 1

Conventional and Recommended Smart Utility Rate Designs for Water Systems and Irrigation Pumps

Conventional Rate Design for Water Pumping		Smart Rate Design Alternative for Water Pumping	
Demand	$10/kW	Demand	None
Energy		Energy	
All Hours	$0.10/kW	Ramping Hours	$0.15/kW
		All Other Hours	$0.10/kW

of usage during the month. This type of rate design encourages water and wastewater utilities to install relatively small pumps, and operate them at a uniform level throughout the day. Table 1 presents a typical utility rate design that applies to water system and irrigation pumps, and a smarter alternative rate design that would encourage the use of larger pumps operated off-peak. We discuss rate design in greater detail in Strategy 7.

Even California utilities that have time-varying energy rates generally impose a "distribution demand charge" that creates the incentive to run pumps during all hours. By eliminating demand charges during off-peak periods, and recovering system capacity costs in time-varying energy rates, electric utilities can replace this incentive with a reward for installing larger pumps that run only at low-cost periods, to provide the same overall level of service.

This strategy assumes that our illustrative utility has approximately 150 MW of pumping load at all hours, and that two-thirds of this load can be shaped into desired hours. One-third is assumed to be essential to maintain distribution system pressure for reliable water service, and is not controlled.

Figure 9 depicts the change in our illustrative utility load shape after re-dispatch of water and wastewater pumping loads.

Updates from the First Edition

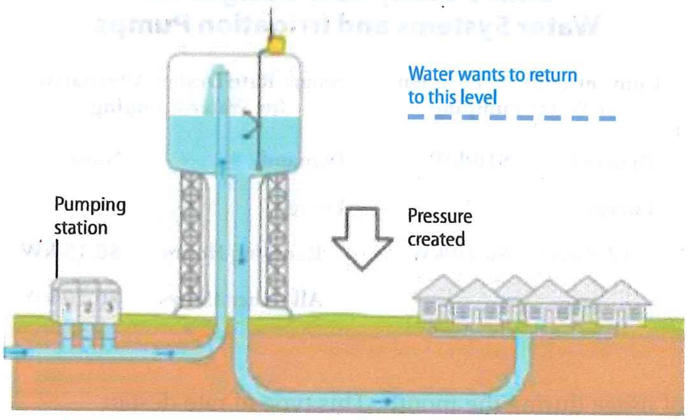
Direct use of **PV electricity for water pumping** in India.

Source: Surya Urza Enterprises

Low-energy **precision application irrigation** can put the correct amount of water directly onto the crops.

Scheduling irrigation pumping to exclude key peak hours has little effect on crop production, and a potential significant economic savings for farmers.

Source: Natural Resources Conservation Service



Source: Bright Mags. (undated). How do water towers work?

Municipal water supply pumping normally keeps water in a tank or reservoir from which water flows using gravity; this eliminates the need for standby generators.

By **filling the tank or reservoir when low-cost power is available**, and turning off pumps during ramping periods and high-cost periods, the water pumping load is shifted, with no impact whatsoever on water customers.

Source: City of Iowa City

The Iowa City wastewater treatment plant has a maximum capacity of 24 million gallons per day but normally treats only about 10 million gallons per day. The **onsite storage capacity** allows some flexibility as to when pumping and treatment are scheduled.

Strategy 4:

Control Electric Water Heaters to Reduce Peak Demand and Increase Load at Strategic Hours

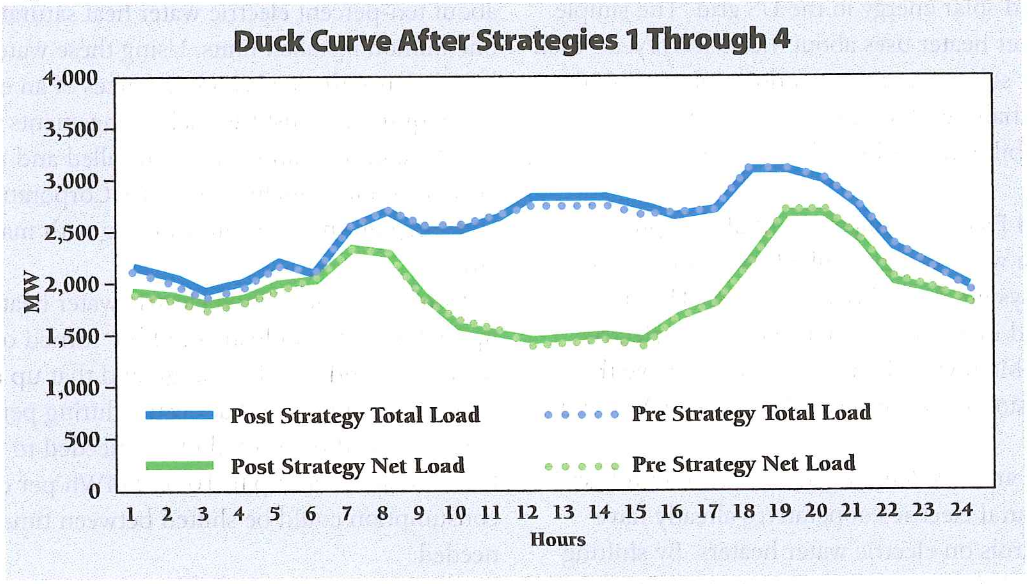
Strategy Description:

Control electric water heaters to increase electricity usage during night hours and mid-solar-day hours, and decrease usage during morning and evening peak demand periods.

Amount:

70 MW (approximately 16,000 units) of electric water heaters controlled to provide high reliability of hot water service, low draw of hot water heaters during key morning and evening hours, and increased draw of water heater loads during off-peak and solar-day hours.

Figure 10

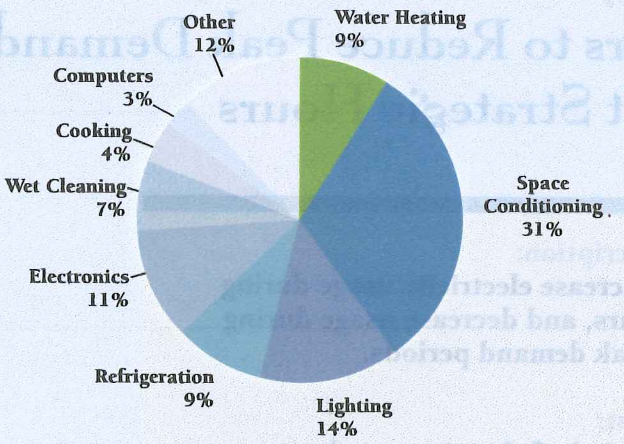


The United States has about 45 million electric water heaters in service. After space conditioning, water heating is one of the largest components of residential electricity demand (Figure 11). This hot water use is concentrated in the morning and evening hours, when residential consumers are getting up in the morning, and again when they return home at the end of the day, contributing significantly to peak demands.

By their nature, water heater tanks are energy storage devices; each water heater is, in effect, a 15-kWh battery waiting to be used, because the water can be heated when power is most available, and the hot water used at a later time. Although the normal pattern of hot water use (and water heater electricity use) is concentrated in the morning and evening, in a world with high levels of variable renewables, it may make more sense to charge these water

Figure 11

Residential Electricity Demand by End-Use



Source: Department of Energy (2012). Buildings Energy Data Book. *Table 2.1.5.*

Table 2

U.S. Water Heaters by Region (×1,000)

	US	North-east	Mid-west	South	West
Total	115,745	21,085	25,896	42,893	25,871
Electric	48,607	5,149	8,005	28,363	7,090
Market Share	42%	24%	31%	66%	27%

heaters at night (wind) or at mid-day (solar).

Control of these water heaters could provide the shaping and storage to integrate up to 100,000 MW of additional variable wind and solar energy in the US grid. The simple arithmetic: a water heater uses about 4,000 kWh/year; each 1 kW of wind or solar generation produces about 2,000 kWh/year. Essentially, each controlled water heater can provide the flexibility needed for about 2 kW of wind or solar generation.

In 2013, Maui Electric Company curtailed approximately 18 percent of the wind energy available from local wind farms owing to system flexibility limitations.[6] Hawaiian Electric estimated in 2014 that control of 6,300 electric water heaters in Maui would enable them to resolve the frequency excursion issues resulting from a 30-MW wind farm.[7]

Water heaters are excellent targets for load control, and more than 100 rural electric cooperatives already have simple load controls on electric water heaters. By shifting water heating load from morning and evening to mid-day (when the solar bulge may appear) and overnight (when wind and thermal capacity is underutilized), water heat energy requirements can be served more economically. But water heaters can also be controlled on a minute-to-minute basis to provide voltage support and frequency regulation service to the grid at a much lower cost than generating units or batteries.

Three different approaches to grid-integrated water heating (GIWH) have promise. First, active control of water heaters, monitoring water heater storage levels and hot water usage, and feeding each water heater sufficient power to ensure that shortages are not experienced. Second, installing larger tanks to ensure a full day's supply without active management during the day. Third, substitution of heat pump water heaters to also reduce total kWh usage, operated at controlled times, together with larger tanks to ensure adequate supplies.

Although electric water heating is dominant in the Pacific Northwest and in the South, every region of the country has millions of electric water heaters (Table 2).[8]

Even the investor-owned utilities in California have about ten-percent electric water heat saturation, or about one million installed units. Using these water heaters to help balance the loads and resources of an electric utility will require new institutional arrangements with customers, but the controls can easily be installed and managed. Several vendors, including Steffes Corporation, Sequentric, and Integral Analytics, are working with many utilities already.

Control of one million electric water heaters means that up to 4,400 MW of load could be "turned on" as needed to absorb wind or solar energy, and that up to 1,000 MW of water heating load that occurs during periods of high demand could be "turned off" as needed to manage peak loads. In addition, up to 10,000 MWh per day of electricity consumption could be shifted between time periods as needed.

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[6] Maui Electric. (2013). Understanding Renewable Energy and Wind Energy Integration.

[7] Hawaiian Electric Company. (July 28, 2014). Demand Response Report. Docket No. 2007-0341, p 64.

[8] KEMA. (2010). 2009 *California Residential Appliance Saturation Study.* Prepared for the California Energy Commission.

For our illustrative utility, with about ten percent of this statewide total load, full implementation of water heater controls on 100,000 electric water heaters would enable it to add about 400 MW at any single hour, and to shift a total of about 1,000 MWh of energy between periods of the day.

To be conservative, we use only one-half of this total (a maximum of 200 MW in any hour, and 500 MWh cumulative in any 24-hour period) to recognize that some water heat energy use already occurs at times convenient to a solar/wind influenced power system, and that the quality of water heating service must not be impaired. This potential storage resource is charged both during mid-day solar hours and overnight off-peak hours. This is a conservative implementation compared with projects being advanced in Canada and Hawaii to use electric water heating controls to add system flexibility.[9]

Electric water heating is more prevalent in multi-family housing, manufactured housing, and rental housing than in the general population. These are lower-income consumers who may benefit greatly from the potential for lower energy bills, but are less likely to have funds available to invest in capital improvements. For this reason, program design is very important to secure this resource.

Implementation of this strategy is best achieved with a combination of program elements, including:

- A first-cost rebate that covers at least the incremental cost of a GIWH unit over a standard unit to make it the economical choice at the time of purchase;
- A monthly bill credit to customers who participate in a GIWH program to make it economical for renters and homeowners;
- A manufacturer and vendor incentive program to ensure high availability and strong marketing;
- A multi-family housing retrofit program, providing funding and technical support to this easily targeted group of customers; and
- A utility service standard that requires new electric water heaters to enroll in GIWH programs.

Figure 10 shows our illustrative utility load after control of 70 MW of electric water heating, equal to about four percent of the residential customer base; in regions with higher penetration of electric water heating than is found in California, the potential would be much greater.

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[9] Integral Analytics (Kallock). (2013). *Renewable Integration Utilizing GIWH Technology.* Peak Load Management Association.

Updates from the First Edition

Real-World Illustrations of the Value of Grid-Integrated Water Heating

Option 1. Active Management
Courtesy of Steffes Corporation

The grid operator or demand-response program manager actively monitors customer hot water levels and usage. Power flows to each water heater are optimized to ensure hot water availability, and to provide both diurnal storage and ancillary services to the utility. Water can be heated to a higher temperature and blended with cold water at the outflow pipe to increase thermal storage capacity.

Left: GIWH control unit, installed on an electric water heater.

Below: Control panel available to grid operator showing available storage and total storage capacity in a water heater.

146°F

16.14 kWh
Current Charge Level

8.86 kWh
Current Reserve Capacity

25.00 kWh
Total Storage Capacity

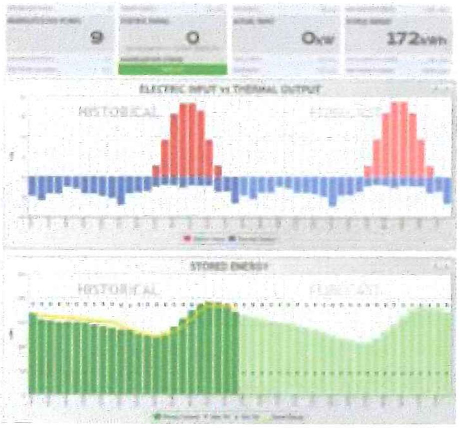
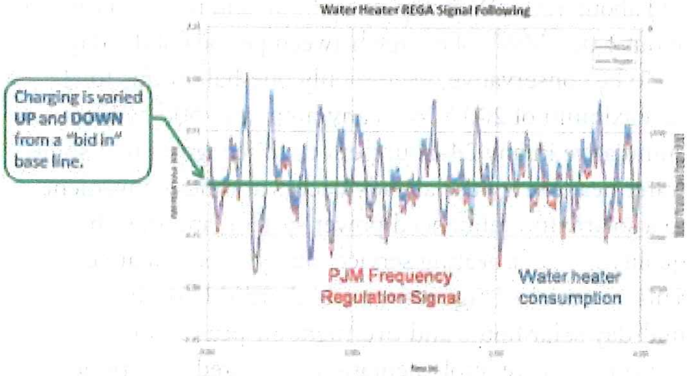


Illustration of hourly data for two days' operation of a group of nine households with GIWH; red illustrates the water heater "charging" with solar or wind-supplied energy; blue depicts hourly consumption of hot water. Green shows the storage of available hot water in each hour.

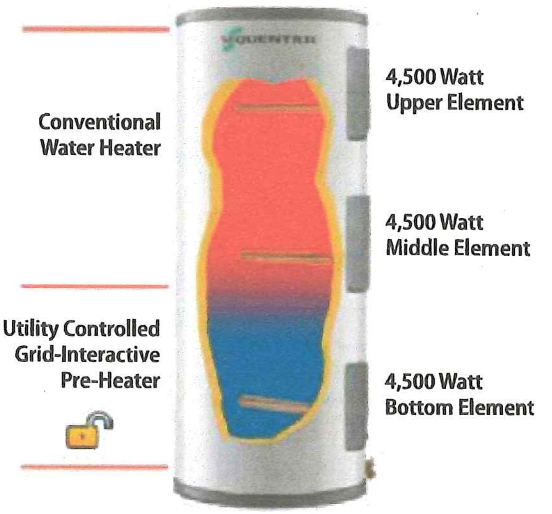


Ancillary services: The red line shows the PJM frequency regulation signal; the blue line is the minute-by-minute following of that signal by a GIWH unit. Because they can be operated second-by-second, GIWH provides more accurate voltage support and frequency regulation than generating units at a fraction of the cost of batteries.

Option 2. Larger Tanks
Courtesy of Sequentric

A larger tank with three heating elements is installed; the utility controls the lower element, while customer hot water usage controls the upper element. The customer has as much hot water under their own usage-driven control as a conventional tank.

Variable-Capacity Grid Interactive Water Heater
US Patent 8,571,692



Above, Sequentric's patented variable-capacity grid-interactive water heater.

Option 3. Controlled Heat-Pump Water Heater Serving Multiple Apartments
Courtesy of Washington State University Energy Program

A large-capacity split-system heat pump water heater is installed to serve the demands of multiple apartment units. Sufficient storage is installed to allow control of the heat pump unit for off-peak hours only. Total kWh usage is reduced by two-thirds, and all of this is during controlled usage periods. Hot water metering can also be used to assign costs to the individual apartment units.

Using Water Heater Controls to Integrate Wind Power

According to the Hawaiian Electric Company's[10] *Integrated Demand Response Portfolio Plan*, GIWH can be remotely turned on and off rapidly, making them a source of regulating reserves with the potential to "counterbalance the intermittency of a given wind or solar power source."[11] Additionally, a "simulation of the results showed that approximately 6,300 units would be needed to effectively counterbalance the frequency excursions associated with a 30-MW wind farm on Maui. Furthermore, results indicate that customer comfort is not affected by the controlled use of GIWH, and surveys point to strong customer interest."[12]

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[10] Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Ltd, submitted in No. 2007 0341, in compliance with Hawaii Public Utilities Commission Decision and Order No. 32054, April 28, 2014.

[11] Hawaiian Electric Company Inc. (July 28, 2014). p. 64.

[12] Hawaiian Electric Company Inc. (July 28, 2014).

Strategy 5:

Convert Commercial Air Conditioning to Ice Storage or Chilled-Water Storage

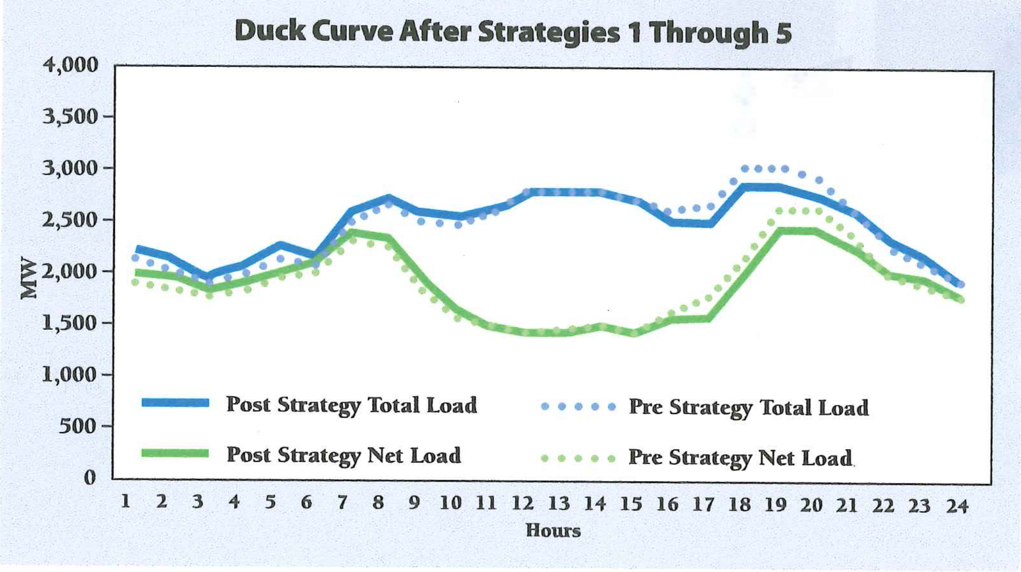
Strategy Description:

20 percent of commercial air conditioning converted to ice storage or chilled-water storage technologies; compressors and chillers operated during the solar day and at night, and curtailed during ramping hours.

Amount:

200 MW of chiller and compressor load controlled to decrease usage in ramping hours and increase usage in off-peak hours; no net kWh savings assumed

Figure 12



Air conditioning (AC) is a huge contributor to peak demands for most US utilities. Late afternoon loads can triple between a cool day and a hot day.

Air conditioning takes several forms. In the residential sector, there are window air conditioners, central air units, and ductless air conditioners. Reducing the load of residential air conditioners by 50 percent is achievable with structural improvements and equipment retrofits. These are all considered as part of Strategy 1, targeted energy efficiency.

In the commercial sector, air conditioning units are large enough that it is cost-effective to install ice or chilled-water storage capacity to shift the cooling load. Ice storage is possible for systems such as those installed on strip malls that rely on five-ton rooftop units, as well as the large 1,000-ton central chiller systems installed in high-rise buildings. Chilled-water storage is an alternative anywhere a central chiller unit is used, and the real estate required for large tanks is available; university campuses are typical applications. We call all of these "storage AC" in this strategy.

Storage AC is not a very complex technology, although sophisticated electronic control systems can optimize the use of the investment. Most of us have an ice-maker in our home refrigerator that dutifully makes 12 ice cubes per hour, allowing us to use 288 ice cubes per day whenever we need them. Storage AC uses essentially the same principle: making cold when the power is cheap, and using that cold when the buildings are warm.

Austin Energy's downtown central cooling system is an excellent example of this. By offering central cooling, the utility has both created a business opportunity to provide chilled water to dozens of office buildings and hotels, and created a market for off-peak electricity. The utility has also shaved approximately 15 MW off its summer afternoon peak demand.

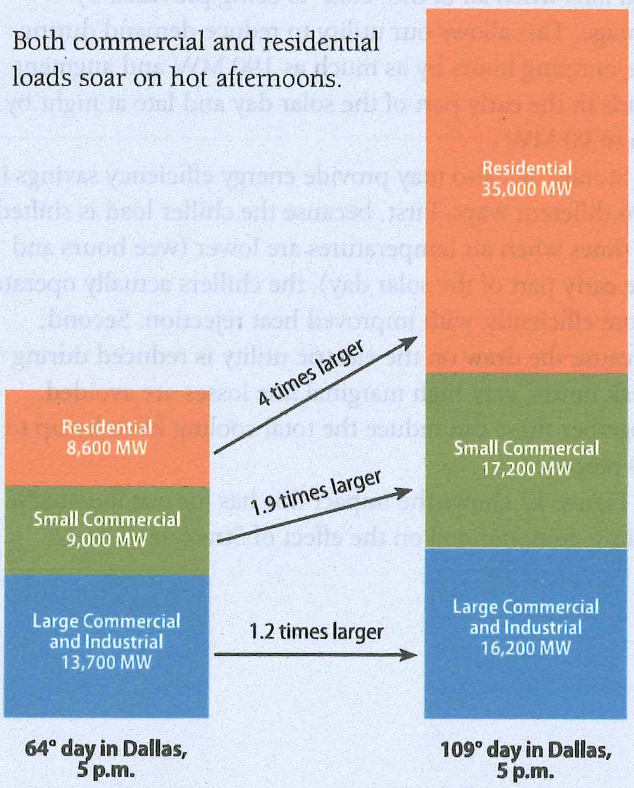
This strategy assumes that our illustrative utility has 200 MW of commercial AC operating at the time of their afternoon peak demand (approximately five percent of the total load), and can shift up to 100 MW of this demand into making ice or chilled-water storage that can provide all of the "cold" during peak hours. A minimum AC load of 10 MW continues during peak hours, to operate pumps and fans when all of the "cold" is being provided by storage. This allows our utility to reduce demand during the ramping hours by as much as 190 MW, and augment loads in the early part of the solar day and late at night by up to 90 MW.

Storage AC also may provide energy efficiency savings in two different ways. First, because the chiller load is shifted to times when air temperatures are lower (wee hours and the early part of the solar day), the chillers actually operate more efficiently, with improved heat rejection. Second, because the draw on the electric utility is reduced during peak hours, very high marginal line losses are avoided. Together these can reduce the total cooling kWh by up to 20 percent.

Figure 12 shows the impact this has for our illustrative utility, compounded on the effect of Strategies 1 to 4.

Updates from the First Edition

Both commercial and residential loads soar on hot afternoons.



Source: Wattles, P. (2012). Demand Response and ERCOT Grid Reliability.

This paper treats residential AC as an energy efficiency opportunity in Strategy 1, whereas commercial AC is partly a load shifting strategy through the use of ice and chilled-water storage.

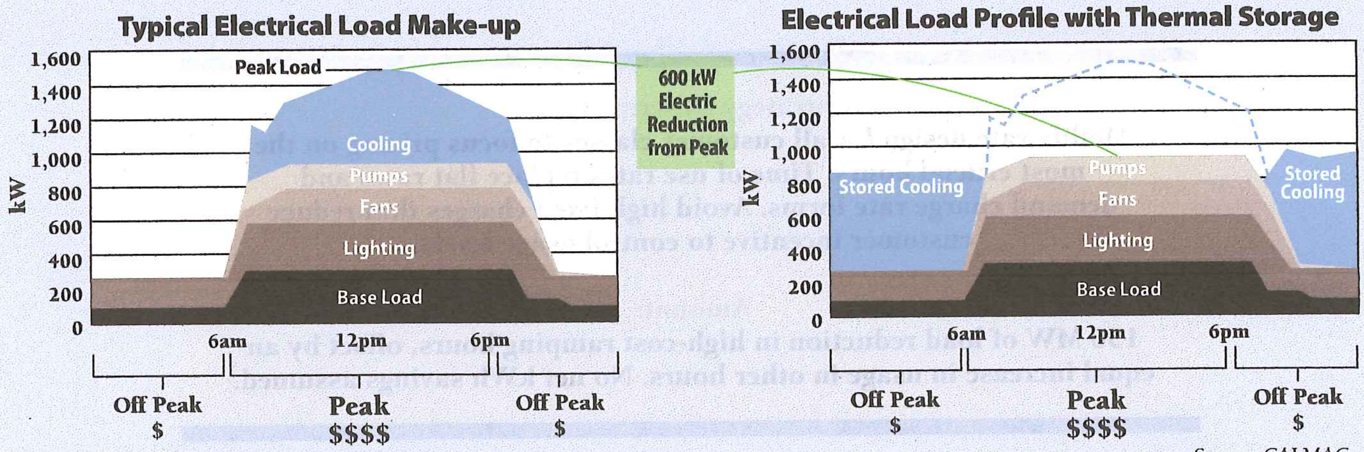
The First Edition assumed a very small amount of storage AC, as the Ice Bear, a storage rooftop AC unit of the type used by retail spaces and other single-story commercial locations, was at that time just beginning to make inroads into the commercial AC market. Since that time, we have learned of the extensive deployment of ice storage and chilled-water storage in the central chiller market, and the Ice Bear has been field-proven and is more widely accepted. In this edition, we consider 100 percent of the central chiller load, and the majority of the retail sector air conditioning loads to be candidates for storage AC.

Real-World Applications of Ice Storage

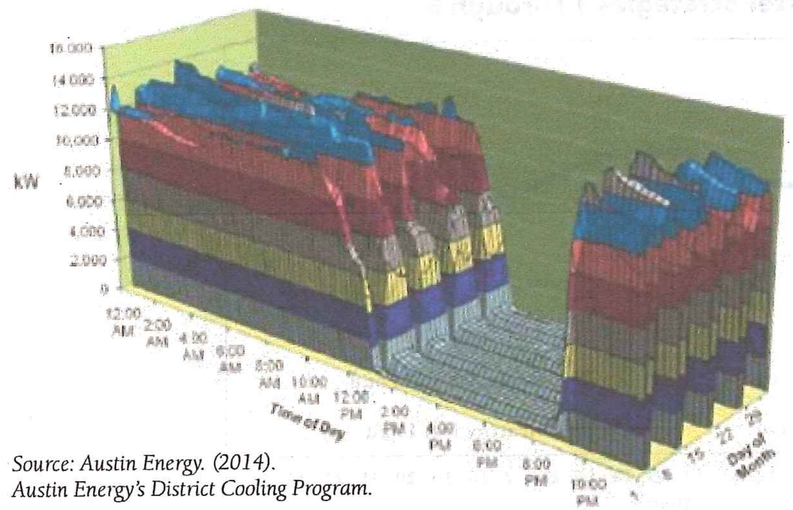
Ice Energy, based in California, is the manufacturer of the Ice Bear. They have developed storage management algorithms to work with available solar PV energy and utility time-varying rates to minimize total consumer costs and shape AC loads to meet changing utility supply profiles.

Ice storage for large and high-rise commercial buildings is commercially used throughout the world. This Bank of America building in New York City requires ice storage equal in size to about 20 automobile parking spaces.

The traditional use of ice storage has been to move the AC load off of the building peak, and fill in the night-time demand. Time-varying energy rates will improve the economics of this technology, but in some solar-rich areas it will be desirable to add cooling load in the early part of the solar day, 10 AM to 2 PM.



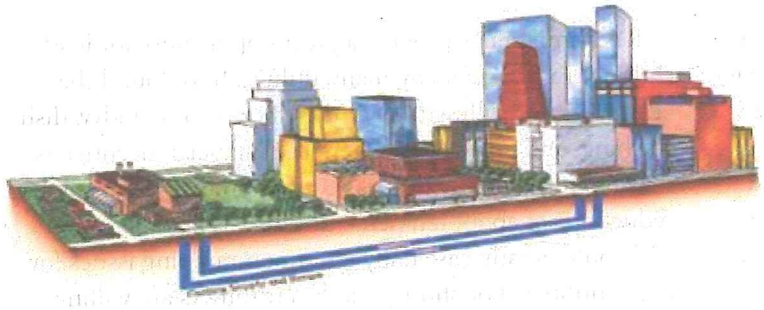
Source: CALMAC



Source: Austin Energy. (2014). Austin Energy's District Cooling Program.

The Austin Energy district cooling system consists of three separate systems, and incorporates more than 100,000 tons of ice storage. The systems draw up to 15 MW of electricity during off-peak periods to make ice, but less than 1 MW during on-peak periods to distribute chilled water, as shown in the load profile graphic across a month's time.

Customers benefit from redundant reliability, space savings, noise and vibration savings, and monetary savings. The utility benefits by avoiding peak demand, enhancing off-peak demand, and generating an additional revenue stream providing cooling service.



Source: International District Energy Association.

Strategy 6:
Rate Design: Focus Utility Prices on the "Ramping Hours" to Enable Price-Induced Changes in Load

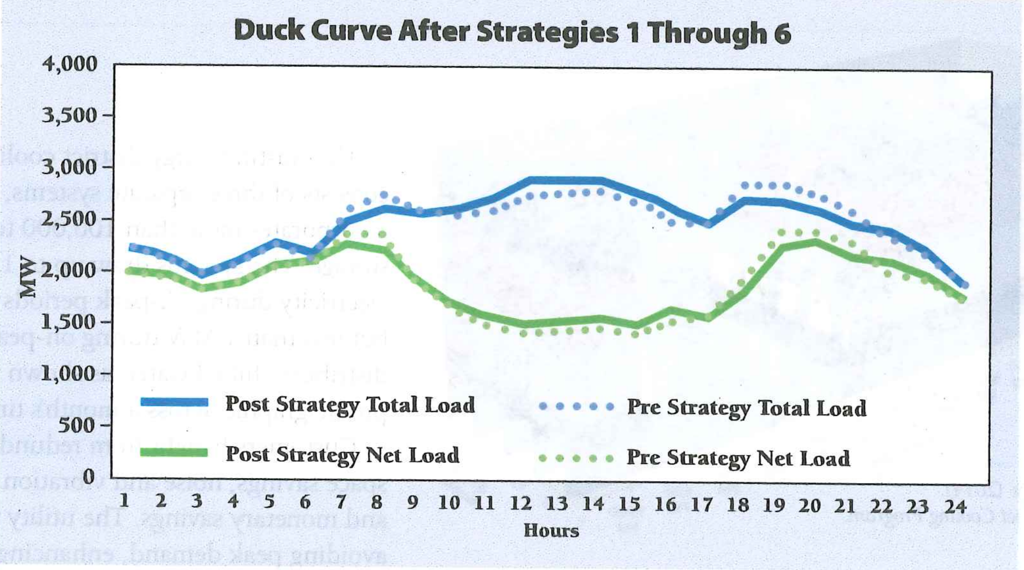
Strategy Description:

Modify rate design for all customer classes to focus pricing on the most crucial hours. Time of use rates replace flat rates and demand charge rate forms. Avoid high fixed charges that reduce customer incentive to control usage levels.

Amount:

150 MW of load reduction in high-cost ramping hours, offset by an equal increase in usage in other hours. No net kWh savings assumed.

Figure 13



Utility systems have evolved greatly in the past half-century, and new approaches to rate design are needed to adapt to these changes. These changes should include time-of-use (TOU) rates for all customers, and the modification of "demand charges" in commercial and industrial tariffs to reflect the diversity of power supply resources that are used to meet loads at different times of the day and year.

Residential rates provide a great opportunity for load shifting. Experiments by many utilities have found that customers are willing to shift their hours for laundry, dish washing, and other tasks where the financial incentive is meaningful. Broad period TOU rates produced typical load reductions of about ten percent. This is a significant shift, and could greatly ease daily afternoon ramping issues for many utilities. For short periods, customers are willing to reduce usage by as much as 35 percent in response to critical peak pricing rates.[13]

Electric utilities use tariffs that contain demand charges for commercial and industrial consumers. Most utilities apply these based on the non-coincident peak demand of each customer, meaning that customer's maximum demand, regardless of when it occurs relative to the system peak demand. This creates an incentive for customers to improve their individual load factors (ratio of average usage to peak usage). One goal of a demand charge is to even out the demand on the utility generation, transmission, and distribution system.

This type of rate design was developed when utility generation was of a homogenous nature, with similar costs for all types of capacity, and when the overall goal was to level out usage and to charge those customers who had uneven usage a higher average price. Today we have some resources used for only a few hours each year, and they have very different costs than baseload resources used throughout the day. Demand charges do not discriminate between these types of resources as well as time-varying energy prices. The effect of a demand charge is that once a customer has "triggered" a demand level for the month owing to usage over a limited period, they have a diminished incentive to control their usage during high-cost or ramping hours at the remaining times of the month.

Today, with variable wind and solar generation creating bulges in the availability of low-cost energy supply at distinct times of the day, it makes more sense to shift these charges toward TOU energy prices, or to concentrate these charges during the hours when the system is expected to be under stress. This can be done in either of two ways:

- Greatly limit the number of hours when the demand charge is imposed, or
- Eliminate some or all of the demand charges and collect this revenue through a TOU energy charge during the hours when the system is expected to face stress.[14]

A rate design change such as that shown in Table 3 would tell the commercial customer to concentrate its high-use energy requirements during the middle of the solar day, from 10 AM to 4 PM, filling the "belly of the duck." Usage during the afternoon ramping period would be much more expensive. Many businesses can adapt to this type of rate. For example, with this type of rate design, office buildings may choose to schedule building janitorial service during regular working hours, rather than leaving lights on until 8 PM for the benefit of janitors. Single-shift industrial customers may schedule their production to conclude by 4 PM. There are many other opportunities for load shaping in response to prices.

Table 3

Typical and Smart Rate Design Alternative for Commercial Customers

Conventional Rate Design		Smart Rate Design Alternative	
Customer Charge	$10/month	Customer Charge	$10/month
Demand	$10/kW	Demand	$2/kW
Energy		Energy	
All Hours	$0.10/kW	7-10 AM	$0.15/kW
		4-9 PM	$0.20/kW
		All Other Hours	$0.10/kW

For this to be effective, it is crucial that utilities not have demand ratchets that would require payment of a demand charge based on usage in a different month, or a period other than the targeted hours. A demand ratchet charges customers throughout the year based on their highest monthly usage, and thus weakens the price information that a peak-concentrated demand charge provides.

Where significant demand charges remain, they should be concentrated on the key hours of the day, so that customers can manage around them.

Although some form of advanced metering is needed to measure and bill a time-varying demand charge or energy charge, these meters may be installed initially only on larger commercial customers, and they can be manually read. It is not necessary to have a full smart grid installation or meter data management system to implement this strategy for larger commercial customers.[15] On most utility systems, these customers make up nearly half of total consumption.

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[13] See Lazar, J., & Gonzalez. (2015). *Smart Rate Design for a Smart Future.* Montpelier, VT: The Regulatory Assistance Project, for an extensive discussion of pricing options for residential and small commercial customers.

[14] We address demand-response programs directed at a small number of hours per year separately in Strategy 9.

[15] Lazar, J. (2012). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project.

In addition, they may be installed for residential consumers who opt for a TOU rate without being deployed system-wide.

One essential element of forward-looking pricing is to minimize the fixed monthly charges that customers face. These should be limited to only the costs that actually vary with the number of customers, such as the service connection, billing, and collection. Shared distribution system costs should be recovered in time-varying energy charges, to give consumers the clearest possible incentives to control usage during key hours of the day.

Our assumption is that targeted pricing can reduce load by seven percent during those hours with the largest gap between total load and the output of wind and solar generators. We assume that the reduced load is offset by increased usage in adjacent daytime hours. Experience suggests that TOU prices that leave the customer too few hours (e.g., only in the middle of the night) to recover needed energy end-uses do not produce very good results.[16]

Figure 13 shows the system load and net load after incorporating load shifts resulting from rate design changes.

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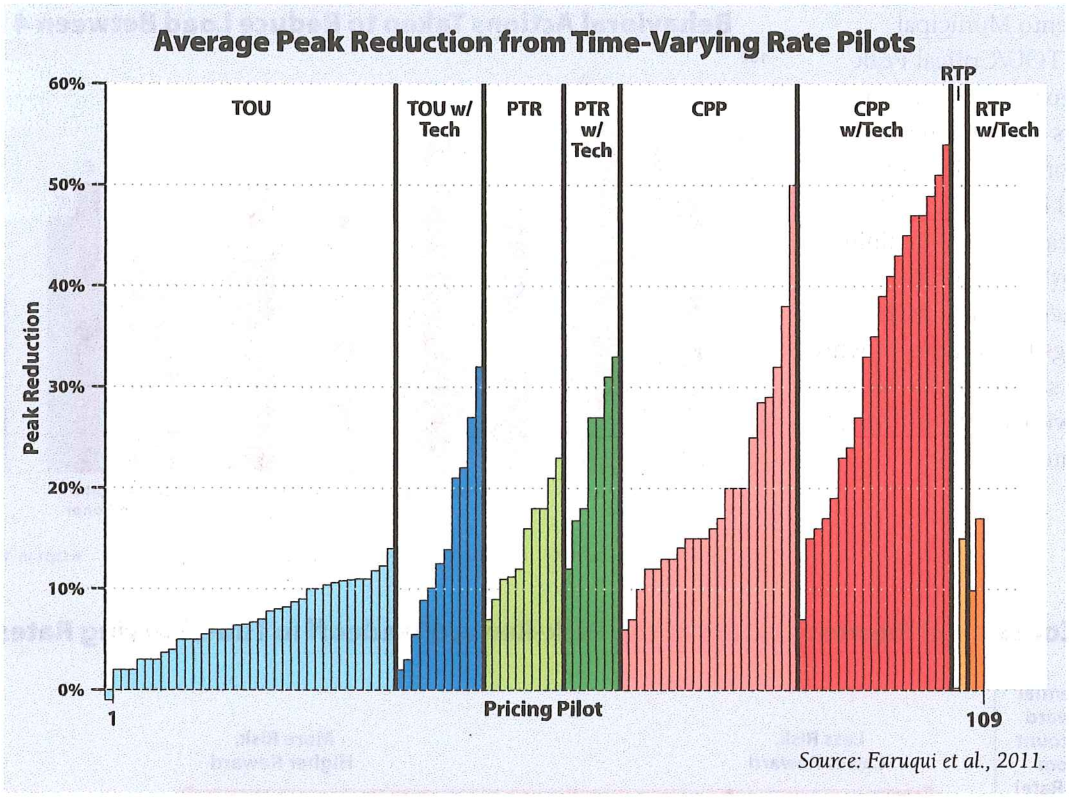
[16] See: Faruqui, A., Hledik, R., & Palmer, J. (2011). *Time-varying and Dynamic Rate Design*. Montpelier, VT: The Regulatory Assistance Project.

Updates from the First Edition



Source: Faruqui et al., 2011.

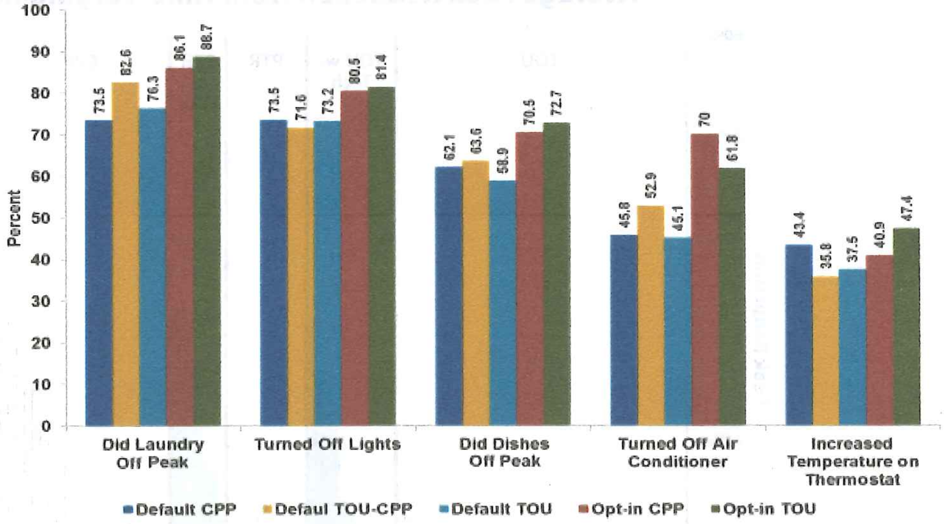
In the Second Edition, we include TOU rates for all customer classes, not just time-varying demand charges for commercial customers. More than half of utility customers now have smart meters, and essentially all new meter installations have TOU capability. Although additional smart grid investments are needed to implement critical peak pricing, smart meters can be used for TOU billing before these systems are complete. The publication of *Smart Rate Design for a Smart Future* since the First Edition provides extensive guidance on forward-looking rate design.

An evaluation of 109 different pricing pilots found that residential customers would reduce peak demand by up to 55 percent in response to a critical peak pricing rate design, combined with technology to enable customers to respond automatically.

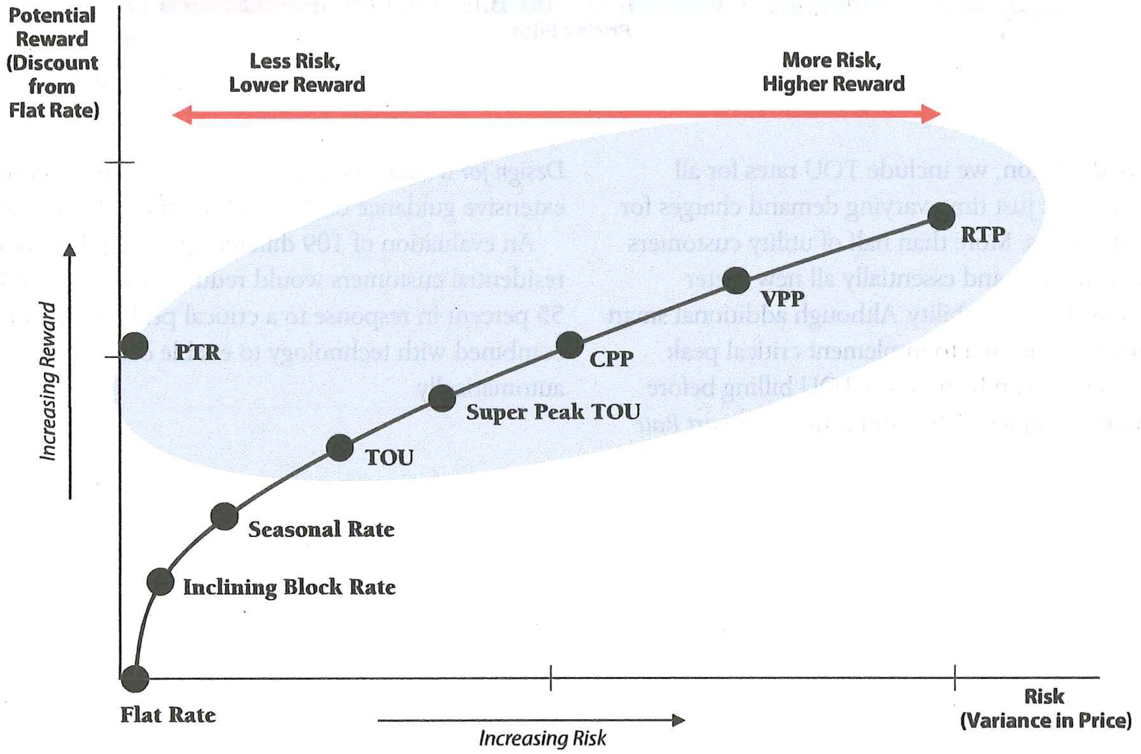
The Sacramento Municipal Utility District TOU/Critical Peak Pricing pilot program found that most customers were willing to take significant actions to reduce their usage at critical hours (right).[17]

Although seasonal and inclining block rates provide significant peak load reduction and significant potential savings for consumers who respond, these savings and benefits are enhanced with TOU and critical peak pricing rates (below).

Behavioral Actions Taken to Reduce Load Between 4 and 7pm



Conceptual Representation of the Risk-Reward Tradeoff in Time-Varying Rates



Source: Faruqui et al., 2011

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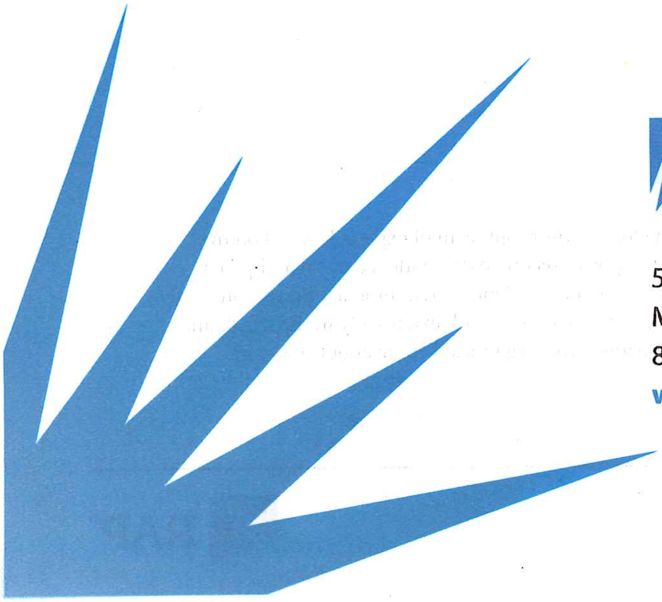
17 Potter, J., George, S., Jimenez, L. (2014). *Smart Pricing Options. Final Evaluation.* Prepared for US Department of Energy.



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Recognizing the Full Value of Energy Efficiency

Available at: http://www.raponline.org/document/download/id/6739

Energy efficiency provides numerous benefits to utilities, to participants (including ratepayers), and to society as a whole. However, many of these benefits are frequently undervalued, or not valued at all, when energy efficiency measures are assessed. This paper seeks to comprehensively identify, characterize, and provide guidance regarding the quantification of the benefits provided by energy efficiency investments that save electricity. It focuses on the benefits of electric energy efficiency, but many of the same concepts are equally applicable to demand response, renewable energy, and water conservation measures. Similarly, they may also apply to efficiency investments associated with natural gas, fuel oil, or other end-user fuels. This report is meant to provide a comprehensive guide to consideration and valuation (where possible) of energy efficiency benefits. It provides a real-world example that has accounted for many, but not all, of the energy efficiency benefits analyzed herein. We also provide a list of recommendations for regulators to consider when evaluating energy efficiency programs.

Meeting the Challenge of Integrating Renewables into the Western US Grid at Least Cost

Available at: http://www.raponline.org/document/download/id/6074

RAP Senior Advisor Lisa Schwartz addressed the challenges of integrating renewables into the Western US Grid in a presentation to the State-Federal Renewable Portfolio Standard Collaborative. Her presentation highlighted the key topics of a paper RAP, in partnership with the National Renewable Energy Laboratory and Exeter Associates, recently prepared for the Western Governors' Association. The project explores approaches for reducing costs to integrate wind and solar in the Western U.S., barriers to adopting these cost-saving measures and possible state actions. Drawing from existing studies and experience to date, the paper identifies nine ways Western states could reduce integration costs—operational and market tools as well as flexible demand- and supply-side resources. Among other recommendations, Ms. Schwartz focused on ways to improve institutional flexibility, explore demand response that complements variable generation, and develop a more flexible generating fleet.

Demand Response as a Power System Resource

Available at: http://www.raponline.org/document/download/id/6597

Demand response refers to the intentional modification of electricity usage by end-use customers during system imbalances or in response to market prices. While initially developed to help support electric system reliability during peak load hours, demand response resources currently provide an array of additional services that help support electric system reliability in many regions of the United States. These same resources also promote overall economic efficiency, particularly in regions that have wholesale electricity markets. Recent technical innovations have made it possible to expand the services offered by demand response and offer the potential for further improvements in the efficient, reliable delivery of electricity to end-use customers. This report reviews the performance of demand response resources in the United States, the program and market designs that support these resources, and the challenges that must be addressed in order to improve the ability of demand response to supply valuable grid services in the future.

Integrating Energy and Environmental Policy

Available at: http://www.raponline.org/document/download/id/6352

Energy issues are environmental issues, and environmental issues increasingly are energy issues. This link is inescapable: energy decisions have profound environmental and public health impacts, and energy-related emissions are changing the heat balance of Earth. The purpose of this paper is to demonstrate that greater integration and coordination of energy and environmental regulation can improve both environmental and energy outcomes—as well as citizens' quality of life and economic wellbeing—and to provide some advice and guidance for moving effectively in this direction.

The Regulatory Assistance Project (RAP)® is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power sector. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability, and the fair allocation of system benefits among consumers. We work extensively in the US, China, the European Union, and India. Visit our website at **www.raponline.org** to learn more about our work.

Other Related RAP Publications Include the Following:

Teaching the Duck to Fly

Available at: http://www.raponline.org/document/download/id/6977

Jim Lazar takes aim at the widely circulated "duck curve" in this brief policy paper, which highlights ten low-carbon strategies for "teaching the duck to fly." Mr. Lazar utilizes existing technologies to address the load shape of emerging utility requirements as increasing penetrations of wind and solar resources create ramping challenges for conventional generation. These strategies not only enable greater renewable integration, but they also enhance system reliability, and reduce capital and fuel costs by modifying the load profiles. Metaphorically, Mr. Lazar teaches the duck to fly, by implementing strategies to both flatten the load and introduce supply resources that can deliver more output during the afternoon high load hours. The resulting "duck" is easier to serve than the projected load would have been without the addition of renewable resources—a desirable outcome for almost any electric utility system, including those without significant renewable energy deployment issues. Fundamentally, this issue is no different from the problem utilities have faced for over a century in matching the supply of energy to changing consumer demand. Only in this case, the challenges created by renewables have evolved over a much shorter time frame. Mr. Lazar provides a set of tools to readily manage the transition to renewables and teach the duck to fly.

Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements

Available at: http://www.raponline.org/document/download/id/4537

While utilities and their regulators are familiar with the energy savings that energy efficiency measures can provide, they may not be aware of how these same measures also provide very valuable peak capacity benefits in the form of marginal reductions to line losses that are often overlooked in the program design and measure screening. This paper is the first of two that the Regulatory Assistance Project is publishing on the relationship between energy efficiency and avoiding line losses.

Smart Rate Design for a Smart Future

Available at: http://www.raponline.org/document/download/id/7680

The electric utility industry is facing a number of radical changes, including customer-sited generation and advanced metering infrastructure, which will both demand and allow a more sophisticated method of designing the rates charged to customers. In this environment, traditional rate design may not serve consumers or society best. A more progressive approach can help jurisdictions meet environmental goals and minimize adverse social impacts, while allowing utilities to recover their authorized revenue requirements. In this paper, RAP reviews the technological developments that enable changes in how electricity is delivered and used, and sets out principles for modern rate design in this environment. Best practices based on these principles include time-of-use rates, critical peak pricing, and the value of solar tariff.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

Available at: http://www.raponline.org/document/download/id/6516

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run costs associated with production and usage. While new technology is enabling innovations in rate design that carry some promise of better capturing opportunities for more responsive load, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change.

Time-Varying and Dynamic Rate Design

Available at: http://www.raponline.org/document/download/id/5131

This report discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.

Key Ideas to Engage Customer Resources to Better Manage the Transition

- Implement time-varying power supply and distribution rates for all customers that concentrate on the key ramping hours for each utility;
- Reduce, eliminate, or time-focus demand charges that otherwise discourage customers from scheduling usage in response to these time-varying rates;
- Explore options for the utility grid operator to control electric vehicle charging;
- Ensure that renewable acquisition programs consider the time of expected energy production;
- Modify energy codes to require ice storage in new air conditioners and controls in new water heaters;
- Expand demand-side management programs to include retrofit of water heater control systems, particularly in multi-family and mobile-home communities where split incentives may prevent participation in price-based programs;
- Provide simple incentive structures to encourage customers to participate in load scheduling and demand response programs;
- Require that integrated resource plans fully consider both the retirement of existing inflexible generation and the inclusion of load control and scheduling strategies;
- Require that integrated resource plans fully consider inter-regional exchanges of energy and capacity to better utilize generation and transmission assets;
- Fully engage water and wastewater utilities in the electric utility resource planning process to ensure that physical storage options are considered; and
- Carefully examine plans for pollution control and other retrofit capital expenditures associated with older power plants to ensure that carbon dioxide values, criteria pollution values, flexibility values, and reliability values of alternatives are fully examined.

We conclude that adequate strategies and technologies are available today to readily manage the transition to a much higher level of variable renewable resources. Their implementation will, however, require time, effort, a change in the utility–consumer relationship, some significant investment, and some serious resolve.

Time is of the essence. Solar and wind energy are becoming more cost-effective every year. The need to displace thermal generation to slow climate impacts is urgent. And the public demands and expects utilities, grid operators, and policymakers to do what is needed to ensure reliable and economical electricity service.

How the Duck Curve With All Ten Strategies Compares to Original Conditions

The existing power system evolved with varying demand, and includes baseload, cycling, and peaking units. It is not necessary to modify load to a completely flat profile in order to eliminate the ramping challenge of the renewable energy transition, only to bring that ramping requirement within the capability of evolving utility grids. The future power system will also contain a mix of resources, and those resources that are acquired to serve growth or replace retiring units can be selected over time to meet the needs of the future.

Figure 17 and Table 4 compare our modified "net load" profile (after solar and wind) with the total load that would have existed without the solar and wind resources and prior to application of our ten strategies. We simply note that the load factor is improved far beyond that which would exist without the renewable resources, and also that the hour-to-hour ramping requirements are smaller than would otherwise exist. Table 4 also compares the results of the Second Edition of this publication to the original. Primarily because of the addition of water pumping load controls, and the expansion of air conditioning storage, the Second Edition improves further on the dramatic results of the original publication.

Thus, our modified post-renewable load is easier to serve than the actual load projected to exist would have been without the addition of renewable resources. The load factor is higher, at 86.5 percent. The maximum hourly ramping requirement is about one-third of the original challenge. The total difference between the highest load of the day and the lowest load of the day is one-third of the original value. This kind of load flattening is desirable for almost any electric utility system, including those without significant renewable energy deployment issues.

It is evident that the net load (including solar and wind) after application of the ten strategies is a much more uniform load to serve from dispatchable resources, even with the non-solar/wind resources, than the load that was forecast for this period without solar and wind. The peaks have been lowered, the troughs raised, and the utility has control over a significant portion of the load to schedule when it can most economically pump water and charge water heaters, air conditioners, and batteries. The effect of the ten strategies is to reduce both peaking needs and ramping requirements. The statistics in Table 4 illustrate this.

The post-renewable and post-strategy load/resource balance would be much easier to manage than that which was forecast absent the renewables and strategies. In fact, using less than one-half of the energy shifting and shaping incorporated in these ten strategies would result in the load following with renewables in 2020 being no more challenging than load following without renewables.

Table 4

Load Factor and Maximum Hourly Ramping Requirements Before and After the Ten Strategies

	Total Load Without Renewables or Strategies	Net Load With Renewables and Without Strategies	Net Load With Renewables and First Edition Strategies	Net Load With Renewables and Second Edition Strategies
Load Factor	73.6%	63.6%	83.3%	86.5%
Maximum Hourly Ramp	500 MW	550 MW	350 MW	198 MW
Total Difference Between Highest and Lowest Hour	1,800 MW	2,000 MW	950 MW	660 MW

Conclusions

It is useful now to compare our final result—with all ten strategies—to the starting point with acquisition of renewable resources, but without the strategies. The difference is quite dramatic. From a sharp peak at 8 PM, our load profile has changed to where the existence of a "peak period" is difficult to identify. Figure 18 shows the end result compared with the starting point.

Figure 18

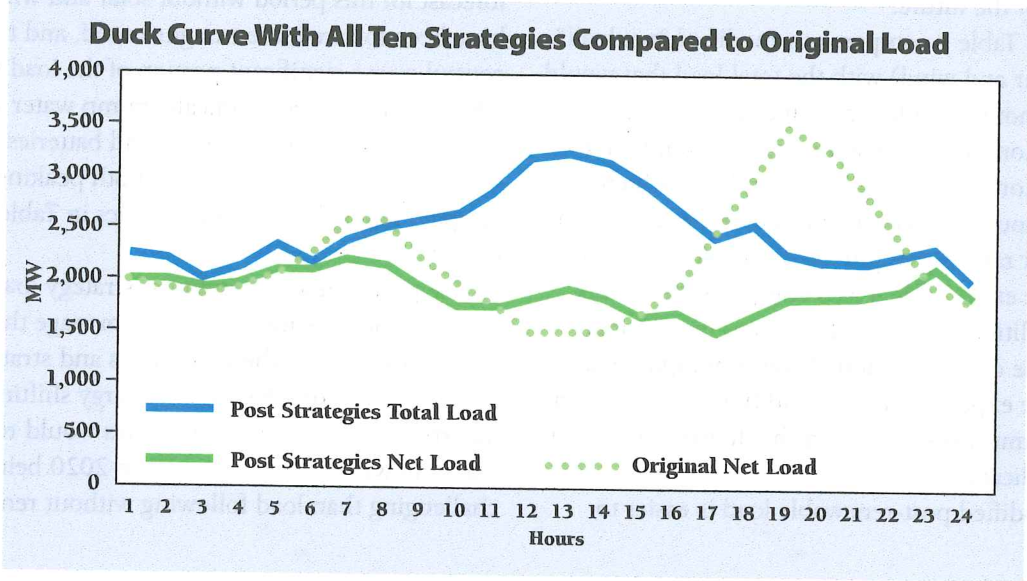
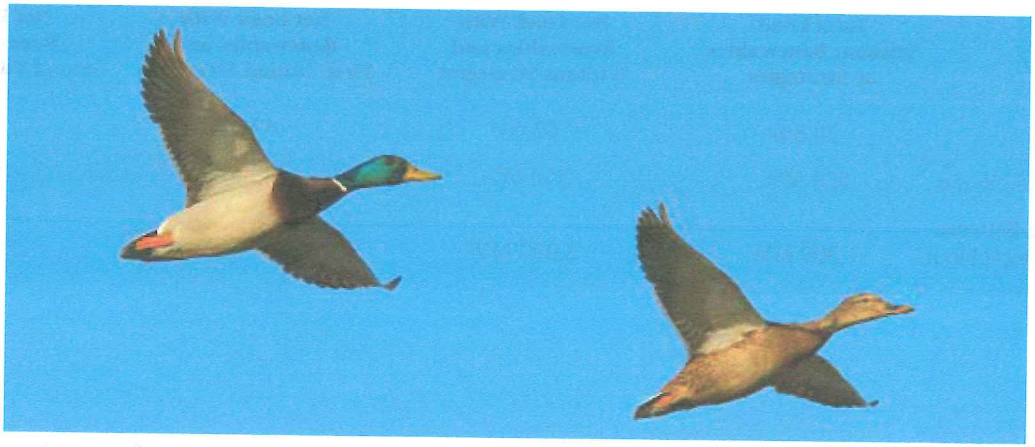
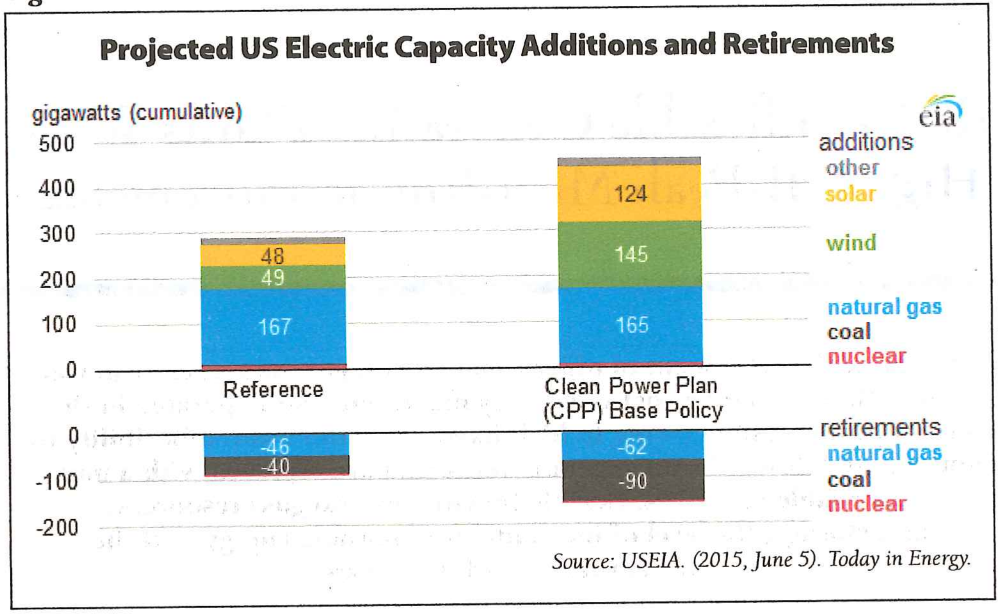


Figure 19
Ducks in Flight



Our newly streamlined duck needs only to stretch his wings, try a few beats, and see if he can become airborne like his cousins.

Figure 17



Source: USEIA. (2015, June 5). Today in Energy.

these units are highly inflexible, the loss of this capacity improves conditions for integration of variable renewable resources. For example, Southern California Edison and San Diego Gas and Electric Company received approval to adapt to the loss of the San Onofre plant by adding a mix of renewable energy, storage, and flexible natural gas generation.

We do not show an adjusted Duck Curve for this resource change because we assume that all utilities, including our illustrative company, have incorporated retirement of aging plants in their existing resource plans (but may or may not be factoring in the increased flexibility of replacement capacity). We discuss the ultimate net load after our proposed strategies in the context of a more flexible generating fleet after describing each of the strategies. If the residual ramping requirement is within the capability of a modern fleet of power plants, including significant levels of high-efficiency natural gas generation, we have met our challenge.

Strategy 10:

Retire Inflexible Generating Plants With High Off-Peak Must-Run Requirements

Strategy Description:

Anticipate the retirement of older coal, natural gas, and nuclear power plants that cannot be cost-effectively maintained and operated in the current power system owing to high fixed costs and limited flexibility to ramp up and down. As these plants retire and are replaced with a mix of renewable resources, flexible (mostly natural gas) resources, and storage, the level of intermittent renewable energy that the system can absorb increases.

Amount:

No specific amount assumed. The "end analysis" is whether the modified load shape after all other strategies are deployed is a shape that the remaining resources on the system can serve.

Many utilities rely on older generating units with limited ramping capability. Much of this consists of coal and nuclear units built more than 30 years ago and that are nearing the end of their useful lives. Indeed, approximately 40 GW of older coal and nuclear units have been retired in the past decade, and another 40 GW are expected to be retired in the next decade.

California is an example of this trend: coal power flowing to California from Arizona, Nevada, Utah, New Mexico, and Oregon is being phased out, and the San Onofre nuclear units were retired in 2013. In addition, California utilities are retiring older steam gas-fired units, generally repowering these sites with high-efficiency natural gas combined-cycle units. Although these retirements do not alter the utility's total load or residual load—the load filled by wind and solar that must be met when these resources are absent—they do reduce its "must-run" thermal capacity during both night hours and mid-day hours. Older gas steam units must be run at about 20 percent of their maximum capacity overnight to be available to meet higher loads during the daytime, whereas modern "flex" natural gas combined-cycle plants can operate on an as-needed basis.

The US Energy Information Administration (USEIA) forecasts retirement of 62 GW of natural gas (mostly less-flexible steam units) and 90 GW of coal plants over the period 2014 to 2040. As indicated in Figure 16, this is expected to be replaced by high levels of wind, solar, and more flexible new natural gas generation.

This strategy leaves more room on the system for replacement units, generally natural gas-fueled, that can be ramped more readily to meet load. There is no question that retirement of coal and nuclear baseload units that were built decades ago will result in higher power costs in the short run, but most of the retirements we anticipate are inevitable because of aging of the units, high costs for pollution control retrofits, and emerging safety and environmental regulations. The point here is not to suggest changing the date of these retirements, but to recognize that they create opportunities to procure more flexible replacement capacity.

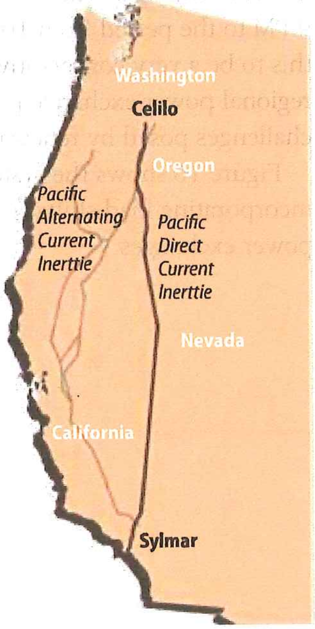
The United States has been experiencing nuclear unit retirements in recent years, evidenced by announcements related to the San Onofre, Kewaunee, Pilgrim, Oyster Creek, and Vermont Yankee reactors, and other potential retirements. The retirement of baseload nuclear units has adverse impacts on greenhouse gas emissions, but because

Updates from the First Edition

California's electricity grid is connected to the Pacific Northwest through a DC intertie that runs from Celilo, Oregon, to Sylmar, California (near Los Angeles), plus three 500-kV AC interties that feed into northern California at the Oregon/California border.

Together these lines can move about 8,000 MW of power into California.

Source: Northwest Power and Conservation Council / Bonneville Power Administration



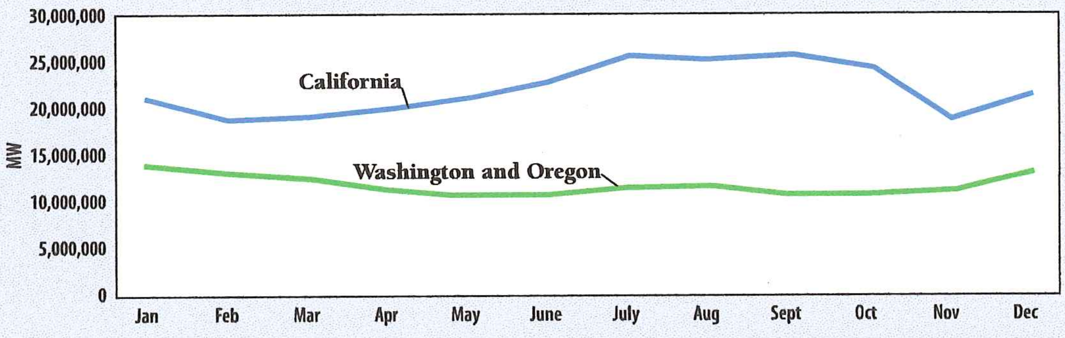
Source: Los Angeles Department of Water and Power

The Los Angeles area is connected to Utah by the Southern Transmission System, originally built to bring power from the Intermountain Coal Plant. This is being phased out of the California power mix, but the transmission line will remain available for inter-regional transactions.

Similarly, transmission lines currently serving Arizona and New Mexico coal plants will become available for other transactions as these units are retired.

California electricity use peaks in the summer months, whereas Oregon and Washington electricity use peaks in the winter months.

West Coast Electricity Consumption by Month



Source: http://www.eia.gov/electricity/data.cfm#sales.

increased in the past decade, with many utilities engaged in peak capacity swaps. With over 8,000 MW of inter-regional transfer capability, using the flexibility of this system to enhance the integration of renewable resources in both regions is widely recognized as a sound and economic option.

Resource exchanges with other regions can also provide diversification benefits. Wind resources in different parts of the west have different production profiles. Some regions have other renewable resources, such as geothermal, biomass, or solar-thermal storage resources, that could be part of mutually beneficial exchanges. Some regions also have low-cost, high-efficiency gas generation that may be available for dispatch and export at the requisite time of need.

This strategy involves drawing upon regional resources and exchanging about 900 MWh per day from 5 PM to 9 PM to the period from 10 PM to 3 AM. We consider this to be a very conservative application of the inter-regional power exchange potential to address the ramping challenges posed by renewable energy development.

Figure 16 shows the system load and net load after incorporating load shifts resulting from inter-regional power exchanges.

Strategy 9:

Use Inter-Regional Power Exchanges to Take Advantage of Diversity in Loads and Resources

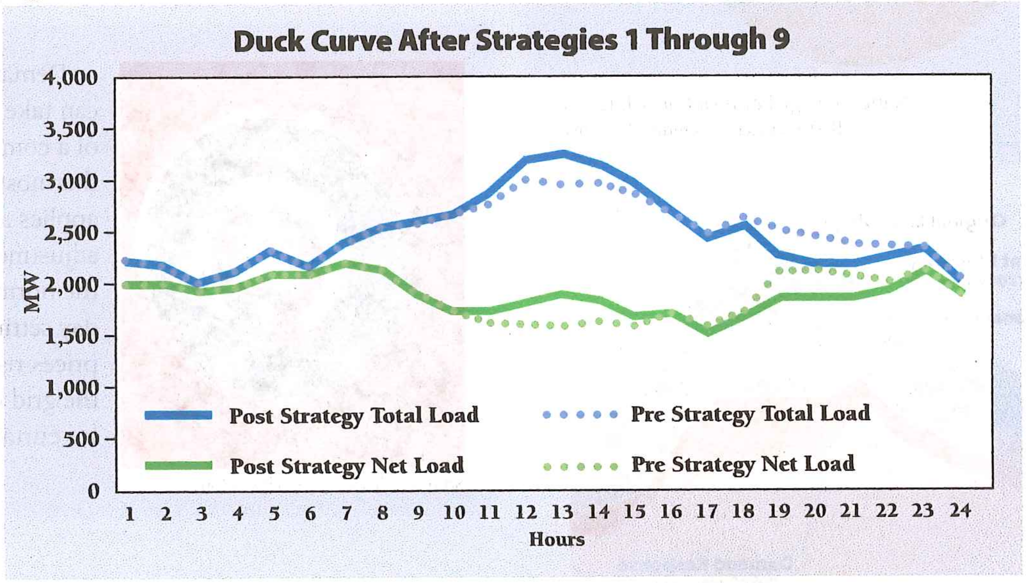
Strategy Description:

Import power from other regions with different peaking periods when it is available; export power to these regions when it is economic to do so.

Amount:

900 MWh per day of exchanges is assumed, an amount equal to about 1.5 percent of total daily consumption.

Figure 16



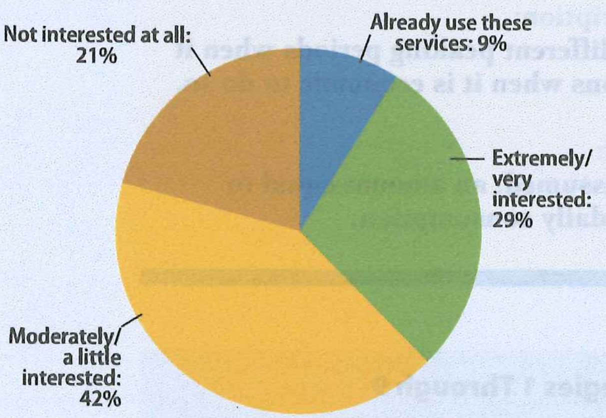
Different regions have different load patterns and different resource profiles. Although solar energy performs best at mid-day, and in summer, other loads and resources have much more geographic diversity. Wind blows at different hours in different places. Some regions are summer-peaking, and others winter-peaking. Some utility systems face peak demands in the morning, and others in the evening. Transmission interconnections, often built for other primary purposes, can enable power exchanges that take advantage of this diversity.

California is a summer-peaking region with maximum loads in the late afternoon. It has thousands of MW of excess capacity during the winter months. The Pacific Northwest is a hydro-rich winter-peaking region, with maximum loads in the mid-morning. It has thousands of MW of excess capacity during the summer months.

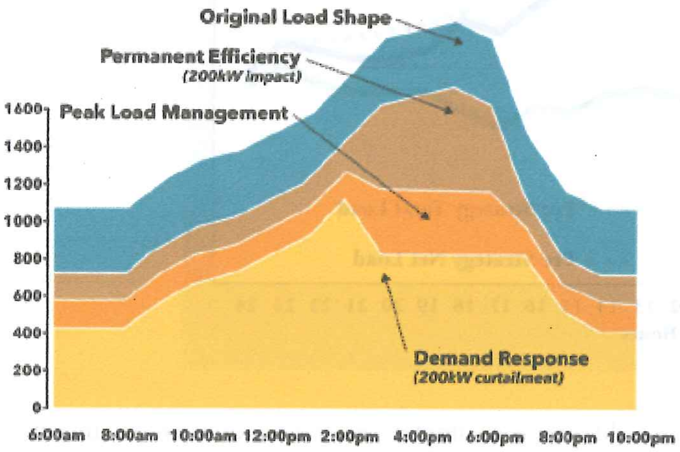
For decades, power has flowed from the northwest to California during the spring runoff, and transmission lines were constructed to facilitate these low-cost energy purchases. Use of transmission lines, originally designed for off-peak usage to also enable on-peak power exchanges, has

Updates from the First Edition

When surveyed, the majority of electricity consumers are interested in reducing their energy bills by curtailing usage for short periods of time when the grid is stressed.


Interest Levels in Demand Response

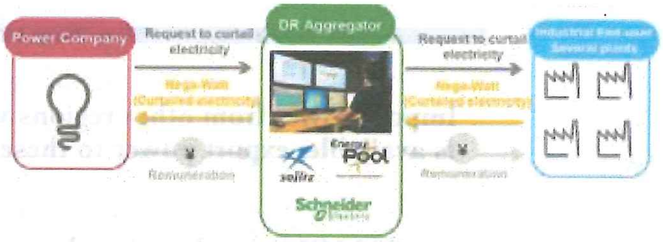
Source: Energy Research Council. (2013). Best Practices: Demand Response.



Source: CPower Corp.

Load reductions from demand response are commonly in addition to other load reductions from permanent efficiency and from peak load management in response to time-varying rates.

In many regions, demand-response programs are operated through aggregators that work with multiple industrial or commercial customers to secure a significant and reliable level of curtailment.



Source: Sojitz Corporation. (2013). Energy Pool, Schneider Electric, Sojitz, TEPCO Launch Industrial Demand Response Demonstration Project for the first time in Japan after Being Chosen for Government-led Next-Generation Energy & Social System Project.

Demand response can take the form of a communicating thermostat that applies additional adjustment (beyond the normal time-of-day setting) when prices rise sharply or the grid operator calls for curtailment.

Source: Flickr Faz Besharation

The experience in New England shows that demand response of about eight percent of peak demand is possible and cost-effective. Given the measures we have already counted, such as time-focused pricing, water pump controls, storage air conditioning, and storage water heating, we assume that three-percent peak demand attenuation (about 100 MW for our illustrative utility) through demand-response programs for the two highest peak hours of a day is reasonable in addition to the measures already identified.

Because the measures we have already counted are largely peak-shifting measures, we assume this residual demand response is economic curtailment—a cut in peak demand without any associated growth in other hours. Figure 15 shows the system load and net load after incorporating load shifts resulting from demand response programs.

Strategy 8:
Implement Aggressive Demand-Response Programs

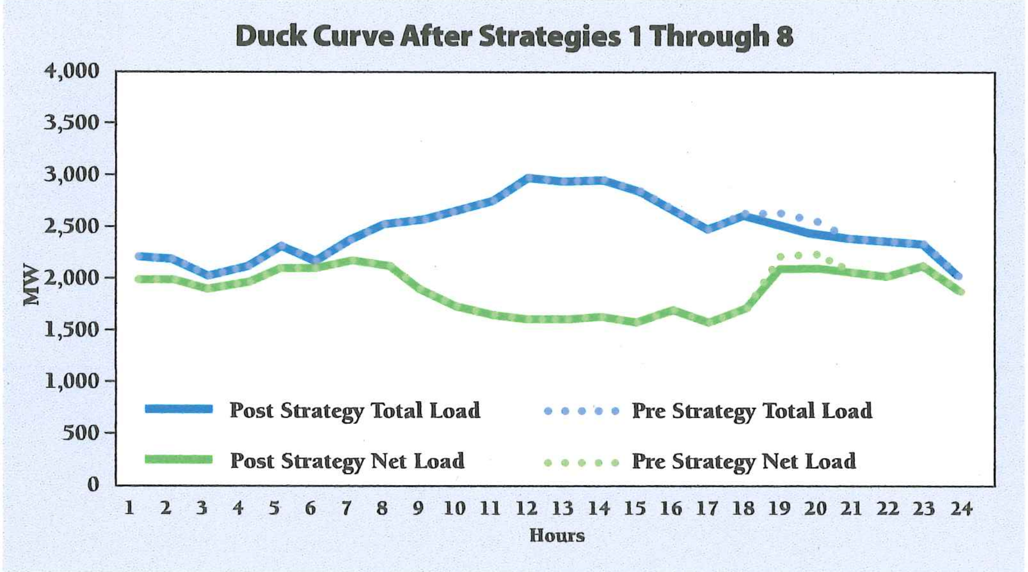
Strategy Description:

Deploy demand-response programs that shave load during critical hours of the year, only on days when system stress is severe.

Amount:

Only 200 MWh of demand response is assumed, because much of this potential will be achieved through Strategies 3 (water pumping), 4 (water heat), 5 (air conditioning), and customer response to Strategy 7 (TOU rates). This is approximately equal to 3 percent of peak demand, or 0.3 percent of total consumer usage.

Figure 15



Many of the strategies listed previously have the characteristic of what is known as "demand response"—programs to entice consumers to change their load patterns. Control of water pumping, water heating, and air conditioning, coupled with customer response to time-varying rates, is assumed to capture most of the potential load shifting that is economic. But for a limited number of critical hours, compensation to customers can achieve additional load curtailment.

Experience with the New England Independent System Operator (ISO-NE) in particular has shown that the creativity of private sector aggregators can attract significant demand response during peak load periods. ISO-NE has been able to secure over 2,100 MW of demand-response commitments (out of a total of about 25,000 MW of peak demand), or about eight percent of peak demand.[20]

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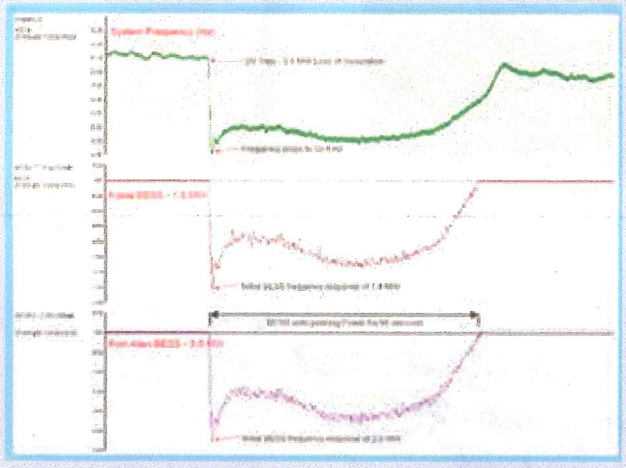
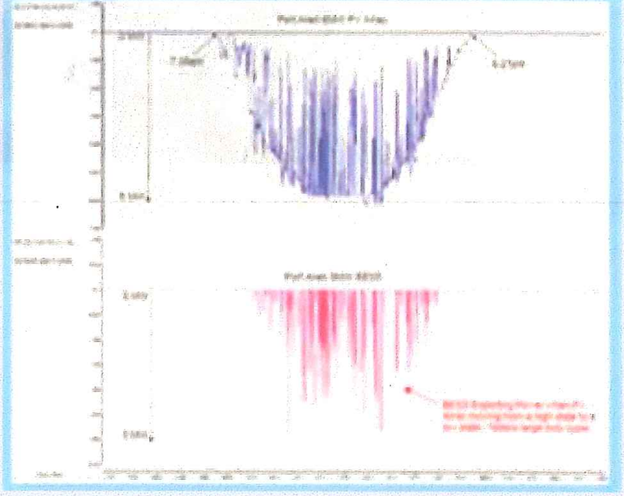
[20] ISO-New England. Demand Resources webpage. Retrieved from: http://www.iso-ne.com/markets-operations/markets/demand-resources.

Kauai Island Utility Cooperative has deployed battery storage on its system. The system has reduced petroleum consumption in three ways: enabling "smoothing" of PV output, enabling the system to serve night-time load with PV-generated power, and avoidance of conventional generation to provide spinning reserves. The utility is on-target to achieve a 50-percent renewable portfolio by 2023.



Source: Yamane, M. (2014). KIUC's Perspective.

This screenshot graphic shows how quickly the Kauai battery storage system responded to a unit trip of one generating unit. The top section shows system frequency dropping to 59.4 hz at the time of the trip. Within 95 seconds, the frequency was restored to 60 hz by automated dispatch of two battery banks responding as shown in the second and third sections. The batteries here are serving a function of spinning reserves.



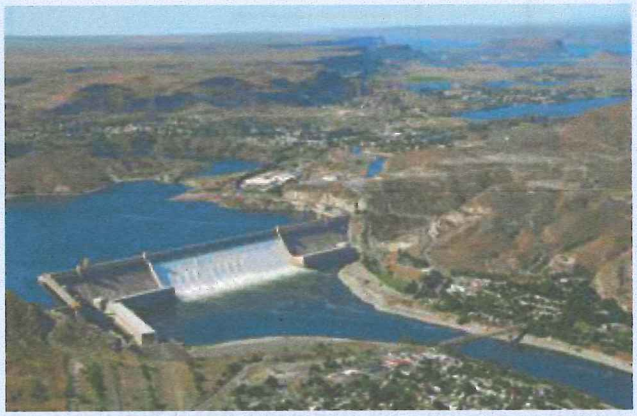
Source: Yamane, M. (2014). KIUC's Perspective.

The upper portion of this graphic shows the minute-to-minute production of a solar farm on Kauai as clouds pass over the area. The bottom portion shows how the battery storage system is used to smooth out this flow. The batteries here are serving a function of voltage support and frequency regulation, in addition to their primary purpose of diurnal storage.

Updates from the First Edition

Tesla offers battery storage systems ranging from multi-MW utility scale systems to the single home Powerwall.

Source: Tesla



Grand Coulee Dam includes 314 MW of pumped storage capability. Six reversible pump/generators lift water to Banks Lake, at the upper right. Although this water normally feeds a 670,000-acre irrigation system, the water can be drawn back through the turbines into the reservoir during peak hours for additional generation.

Source: U.S. Bureau of Reclamation

and require additional transmission investment to bring that capacity to the service territory. Other large-scale technologies, including large-scale compressed air energy storage, are emerging. Another role for storage is fast response for ramping and system reliability, and here batteries and flywheel systems seem to be the preferred technologies.

There are targeted locations where electricity storage can be cost-effective and should be pursued. These include placement at strategic points where storage provides supplemental generation capacity during some hours, and a place to "park" surplus generation from high renewable penetration or nuclear generation at times when it is not needed for current demand. It also includes areas where strategic storage can help avoid expensive transmission and distribution system upgrades and provide ancillary services such as frequency control and voltage support. For example, installation of battery banks at the site of wind generators where they may help avoid transmission capacity upgrades should be compared to installing batteries at distributed points where they may displace distribution grid upgrades.

This strategy includes both installation of new battery banks or compressed air storage units, as well as the use of existing batteries, such as those in electric vehicles and uninterruptible power supplies (UPS). The strategy is to selectively charge storage batteries when power is available and to use the battery resources when power is scarce. For example, one hospital is using the existing batteries for the UPS in its surgical suites (which are seldom used in the late afternoon) to peak-shave their demand charge on particularly hot days.[18] This allows both testing of the UPS systems and reduction of electricity costs.

The simplest application of this principle of dual-purpose batteries is to turn electric vehicle chargers on and off as power supply market conditions change and to meet ancillary service needs. More sophisticated selective discharge systems—vehicle to grid—are being tested and may become available within this decade. These vehicle to grid opportunities are not considered here, but may soon emerge as a valuable resource.

By 2020, this would include a significant number of controllable electric vehicle chargers, plus discrete battery or compressed air energy storage installations at substations or other locations where distribution capacity upgrades are imminent. The economics of these must be compared to the full generation, transmission, distribution, and environmental benefits they provide, not just to the deferred distribution capacity upgrades.

For purposes of this paper, we assume that the illustrative utility system would add energy storage available up to about one percent of total load, or a total of 500 MWh of electricity storage, with a maximum charge or discharge rate of 100 MW per hour.[19]

There are many regions where pumped storage hydro capacity greatly in excess of this amount exists today. We assume 20-percent round-trip losses, so 620 MWh of energy must be generated in order to provide 500 MWh of usable energy augmentation during peak load periods, but displacement of peaking unit operation and avoided high marginal line losses may save more fuel in the 500 MWh of generation displaced during peak hours than is used to produce 620 MWh during periods of surplus energy.

Figure 14 shows the system load and net load after incorporating load shifts resulting from targeted electric energy storage.

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[18] Personal discussion with Geoff Glass, Providence Hospital Network, 2014.

[19] In October 2013, the California Public Utilities Commission directed regulated utilities to acquire 1,325 MW of storage capacity by 2020 in Rulemaking 10-12-007; Strategy 8 is slightly less aggressive than the California requirement.

Strategy 7:
Deploy Electrical Energy Storage in Targeted Locations

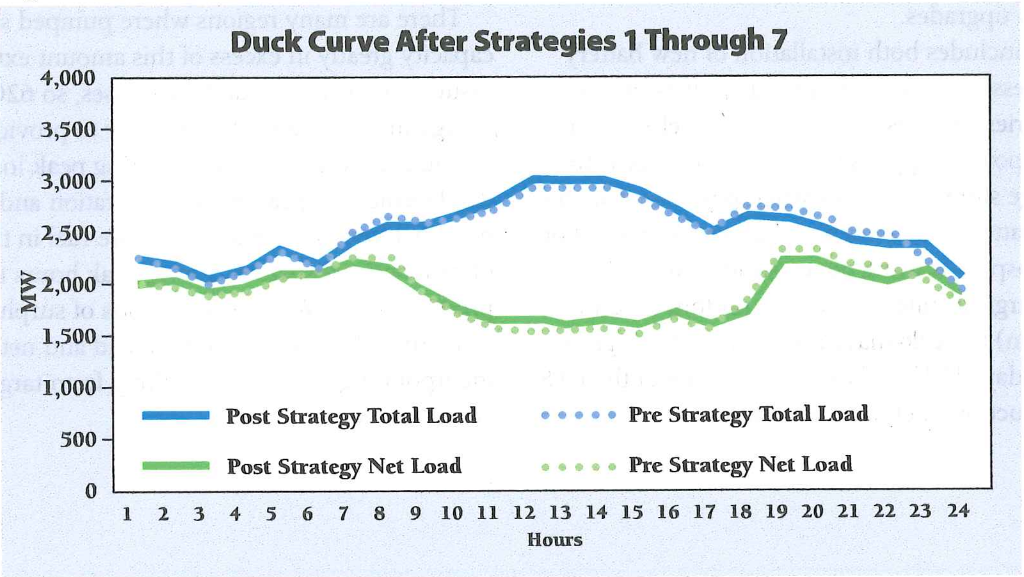
Strategy Description:

Identify locations where electricity storage, including batteries, can provide more than one function. Deploy storage to simultaneously reduce the investment needed for transmission and distribution, and to provide intra-day storage of energy from intermittent renewable resources.

Amount:

Electricity storage capacity of 500 MWh, approximately one percent of daily consumption, is deployed. A net increase in total kWh is assumed, owing to round-trip losses associated with charging and discharging storage systems.

Figure 14



Electrical energy storage is very expensive, but costs are dropping rapidly. Storage is a potential part of a comprehensive approach to system optimization. Although there are multiple technologies currently available, including batteries, pumped storage hydro, compressed air energy storage, flywheel technology, and perhaps others, all of these are expensive. Compared with thermal and mechanical energy storage addressed in Strategy 3 (water pumping), Strategy 4 (water heat), and Strategy 5 (ice and chilled water), where the energy is stored in the form it is eventually used, all electricity storage options include significant "round trip" losses as electricity is converted into another form (mechanical or chemical) energy, and then reconverted to electricity. These losses range from as little as 15 percent for lithium-ion batteries, to as much as 35 percent for compressed air energy storage systems.

Storage has multiple roles. One is bulk energy storage, and pumped hydro has been used extensively for this. These storage units are typically in remote locations