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Energy Technologies Area
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Water-Energy Considerations in California's Agricultural Sector and Opportunities to Provide Flexibility to California's Grid

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June 7, 2019

Abstract

Water and energy use on farms are deeply linked, and trends changing the way water is used on farms have implications for the electrical grid, and vice versa. In 2014, California's agricultural sector accounted for approximately 80% of the state's water consumption and 5% of its electricity use. The majority of the electricity was for surface conveyance and groundwater pumping. Diminishing surface water availability and increasing reliance on groundwater pumping are likely to increase future energy demand. These trends are coincident with farms embracing new precision irrigation technologies that increase water productivity and crop yield, but may have the potential of other collateral effects, such as increasing energy intensity of irrigation and total electricity use, and thus demand on the grid. The impacts of these technologies and their loads on the electrical grid have been explored only to a limited degree, and the potential grid benefits afforded by these technologies have been studied even less. For example, studies show that California's increasing adoption of renewable electricity

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may result in excess generation during certain periods of the day, and that responsive load management (i.e. demand response) may be a cost-effective method to shift loads to utilize this excess generation. The degree to which farms in California do or can provide responsive loads has not been explored. In this paper, we explore whether farms that are adopting technologies and automation for irrigation management can provide co-benefits to the grower and the electrical grid. To do so, we define the characteristics of future grid needs specifically related to responsive load management, explore existing market mechanisms and policies for proving those resources, estimate the temporal distribution of energy use for irrigation in California, and develop scenarios of how irrigation loads might meet these needs. We conclude by exploring potential ancillary service benefits and associated revenues that California's agricultural industry may provide. Ancillary services include using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour. With higher penetrations of renewable resources, larger quantities of ancillary services will be necessary and may become more valuable to the grid than traditional demand response. Ancillary services from agricultural loads is a nascent topic, and no such analysis has been conducted to quantify its benefits to our knowledge.

Introduction

California's agricultural sector uses a significant amount of water and electricity. A recent review of California's electrical use estimates that about 5% of the state's total annual energy use is for conveying water for agricultural irrigation [1], and various reports estimate that about 80% of the state's total water use is for crops [2]. Recent energy and water policies may present particular opportunities or challenges to this industry. For example, state goals to increase the use of renewable sources of energy may affect the cost and availability of electricity (see e.g., California Senate Bill 100, and Executive Order S-14-08)[3,4], and new mandates to increase sustainable management of the region's groundwater system may catalyze the installation of equipment that improves groundwater monitoring and management (see e.g., California Assembly Bill 1739 and Senate Bill 1319)[5,6].

The implications of these mandates are yet to unfold. Several recent energy studies have suggested that providing responsive load management through demand response (DR) across industrial, agricultural, and water sectors could bring benefits to the electrical grid, and that electricity markets might provide sufficient financial incentives to enable them (see e.g., Hummon, et al., 2013 [7]). Although significant, these reports do not study the agricultural industry in great detail, including whether water management trends in the industry are adding to or diminishing peak load stress on the grid. Moreover, the industry is thought to be highly cost-sensitive, and profit margins are believed to be quite small, ranging from 7%–14% [8]. The degree to which the agricultural industry is able and willing to participate in utility or grid programs has not yet been well explored. Such a study becomes even more important as farms install onsite generation (wind or solar) and adopt automation (mainly to lower their labor cost as wages increase). It is important to explore those changes and how they will affect farmers' participation in various grid services.

Traditional DR strategies on farms have enabled participation in capacity programs, such as seasonal and day-ahead markets, and/or load shift programs, such as utility-provided time-of-use (TOU) rates [1]. While significant, the evolving needs of the grid are likely to present new and additional market opportunities. In particular, a recent study of California's energy markets suggests that sub-hourly load management to meet ancillary service (AS) requirements could provide significant value to the grid [9], and that industries with load management technologies that enable rapid, automated response could fulfill a significant portion of these grid needs. The degree to which agricultural pumping under current or future operation may meet these criteria has not been discussed in the open literature. Olsen, et al. (2015) identified potential barriers for the agricultural industry to participate in retail DR programs with long dispatch durations (> 1 hour) but not in short-duration DR. They identified barriers, including limited irrigation capacity, lack of mechanisms that streamline grid integration and communications, poor irrigation controls infrastructure, and a perceived overall inflexibility of water delivery and application methods by growers [10].

Changes in irrigation practices on farms are likely to affect the magnitude and distribution of electrical demand, as well as the flexibility of that demand [11]. To that end, technologies, such as pressurized irrigation, that are installed to improve water application efficiency may, in some cases, lead to greater water consumption, and thus energy consumption [11]. More efficient irrigation technologies can encourage farmers to increase their acreage; grow more profitable, water-intensive crops; and shift from surface to groundwater in order to pump on demand [11,12] — all of which can increase energy consumption. Even if overall agricultural water use is reduced, pressurized irrigation could lead to increased energy use, which would present added stressors to the grid in the future. Efforts are underway to limit the amount of groundwater pumping by California farmers (e.g., the Sustainable Groundwater Management Act); however, it will take several years for the Groundwater Sustainability Agencies to reach their groundwater withdrawal targets.

At the same time, the installation of improved water management technologies may enable greater flexibility when the electricity is used over the course of a day and season, and thus could provide greater and more varied types of responsive load management to the grid. Trends in farm water and energy management have not been explored in much detail in the open literature, owing in part to the disparate nature of these bodies of research. They have also not been discussed in relation to the specific demands or opportunities to the electrical grid, in general, or specific to California.

To start, we explore these interactions from an overview perspective. First, we provide background information about the current status and changing situation for electricity, water resources, and agricultural loads. We also review the relevant literature on water use on farms as it pertains to their electrical load characteristics, estimate current electrical use profiles, and highlight the ways through which the loads can hypothetically satisfy various grid needs. Finally, we conclude with an illustrative example of how one might compute the value proposition and magnitude of several forms of AS in California in order to elucidate the potential for complementary benefits to the grower and the electric grid. Although this study is not a comprehensive report on all factors of the water-energy considerations for the agricultural sector, the contribution of this paper is a holistic macro-level analysis, both qualitative and quantitative, of the electrical demands and flexibility opportunities from California's agricultural sector.

The Electricity Grid

When viewing trends in electricity generation and consumption in California and their implications on agricultural energy use, one must not overlook the impacts and implications of the greater penetration of renewable sources of electricity. Specifically, understanding their relevance to agricultural electrical use requires a broader understanding of power generation and load to meet the grid needs. A new California target calls for meeting 100% of state's retail electricity sales with renewable energy by 2045 [3] and reducing greenhouse gas (GHG) emissions to 40% below 1990 levels by 2030 [13]. To reach this goal, the state is aggressively enabling various financial incentives to increase the installation of solar and wind generation throughout the state [14]. Figure 1 shows the annual production of solar and wind generation in the past 24 years, and Figure 2 shows the predicted cost of production from solar and wind generation in 2030.

The implications of these data are the noticeable increased production of solar and wind energy, and that it is coupled with the decreasing costs of electricity production. If these projections hold, concerns arise on the effort, and thus costs, to mitigate the possible impact that intermittency of energy production may have on the electrical grid, and what may be needed to maintain grid reliability and power quality [15]. This is illustrated in Figure 2 by showing that most wind and solar energy production is largely non-dispatchable. *Non-dispatchable* electricity refers to sources of generation that cannot be ramped up or down on demand. Renewable sources such as wind and solar are considered non-dispatchable because their output cannot be modulated similar to thermal powerplants such as natural gas. A large presence of non-dispatchable electricity on the grid can potentially cause complications with balancing the grid and its reliability.

Figure 2 also shows the declining trend for cost and thus marginal value of energy diminishing. If so, any electricity source necessary to ensure grid reliability may become economically untenable. In other words, California may face conditions in which significant amounts of low-cost renewable energy — and its associated intermittency — negatively affects grid stability, in turn driving up the costs to manage reliability. It is important to mention that there is a more complex relationship between Levelized Cost of Electricity (LCOE) for new installations (long-term) and marginal value of energy (short term) than is presented in Figure 2. Other factors such as subsidies, renewable portfolio standards, etc. impacts which investments get made and what the marginal value of energy ends up being.

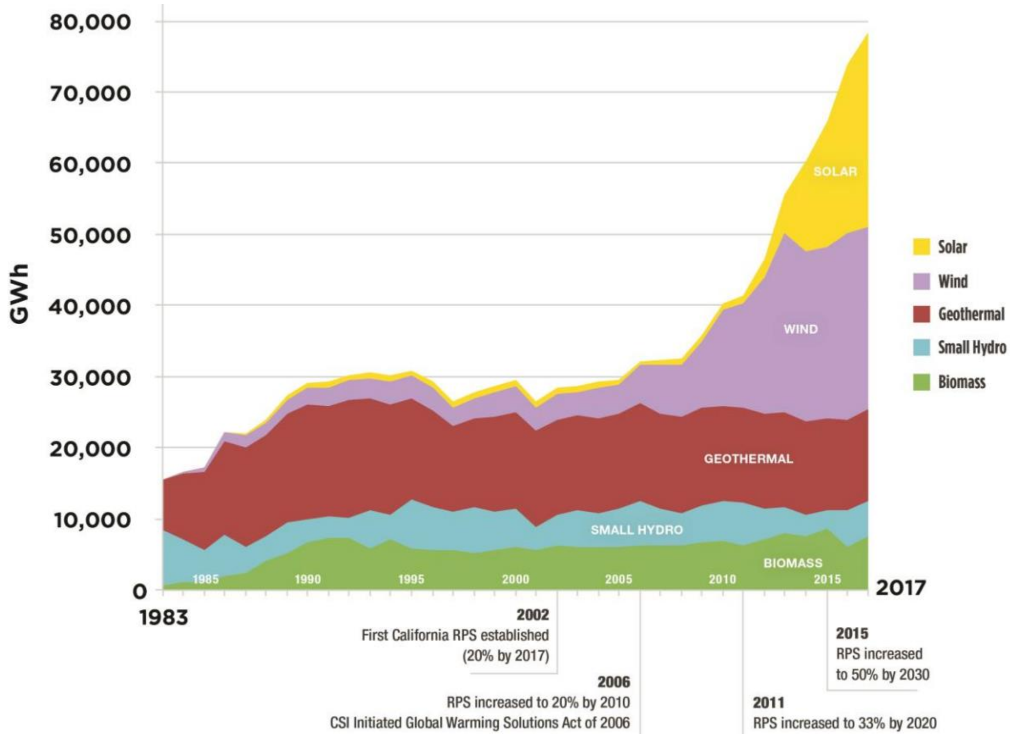

Figure 1: Renewable energy generation 1983–2017 by resource type. Timeline of various California Renewable Portfolio Standards are labeled in the figure [14]**.**

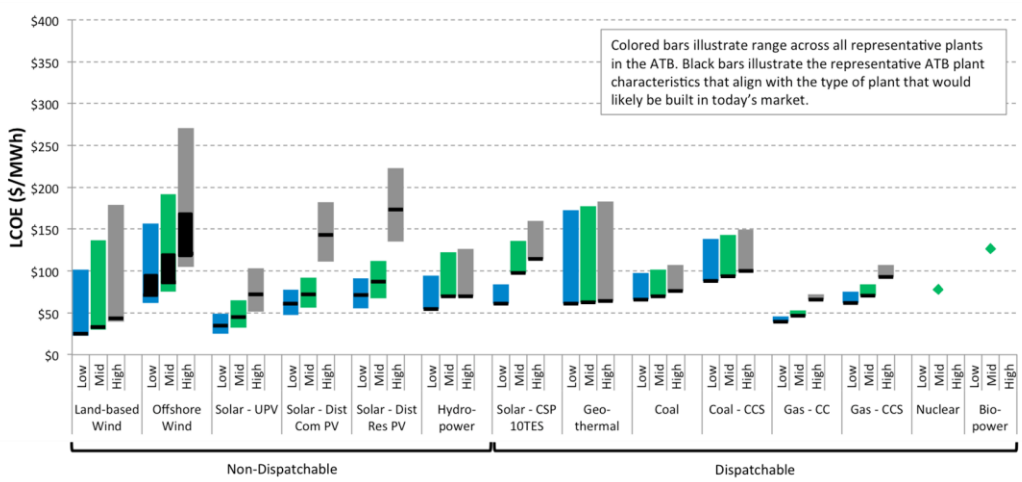

Figure 2:[2] Predicted levelized cost of electricity (LCOE) for 2030 based on 2017 market conditions [16]**.**

2 Figure abbreviations: Annual Technology Baseline (ATB), Utility Photovoltaic (UPV), Photovoltaic (PV), Commercial (Com), Distributed (Dist), Concentrated Solar Power (CSP), Thermal Energy Storage (TES), Carbon Capture and Sequestration (CCS), Combined Cycle (CC).

Another grid reliability concern involves the time when energy is produced and needed. Figure 3 shows the California Independent System Operator's (CAISO's) assessment of the anticipated net electricity demand during a typical spring day, from demand and supply perspectives. As discussed in the California DR potential study, increasing availability of renewable sources during certain times of the day implies the potential for excess generation midday and a shift in the peak system load from the afternoon to the late afternoon to early evening [15]. It also may result in the rapid and short-duration ramping up and down of demand during the morning and late afternoon periods. The shape of Figure 3, commonly referred to as a "duck curve" implies further changing needs for the electrical grid.

For example, the implications of California's 100% renewable portfolio standard mentioned above might exacerbate the duck curve, but it may enable farm loads to provide easement or benefits. Significant work has been done to forecast various hypothetical scenarios of what high penetration of renewable power in California will look like; Figure 4 shows one of these likely energy mixes [17]. Thermal power plants are likely to provide base supply during the morning and evening hours and then ramp up or down based on the availability of solar resource, irrespective of whether the solar resources supply the electricity behind or ahead of the customer meter. Therefore, thermal generation must be reduced to a minimum capacity during morning hours as solar resources come online, but must remain spinning for contingency and evening ramp up. In the absence of cost-effective energy storage, excess solar generation during the midday hours must be curtailed [18]. In addition, higher solar generation is causing lower-than-usual *net demand* (i.e., demand minus renewable generation), which results in steeper morning ramp-down and evening ramp-up [19].

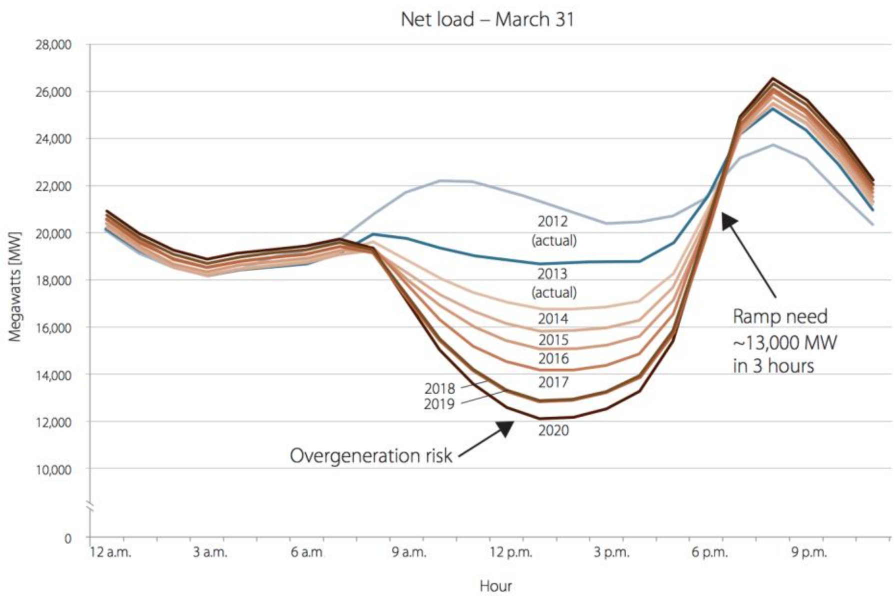

Figure 3: Net demand of the California grid in a typical spring day [20]**.**

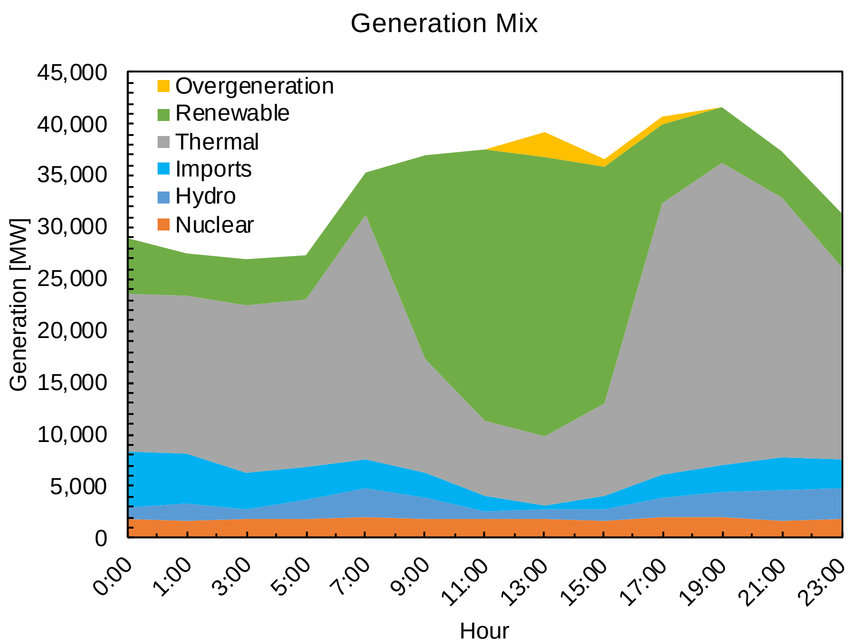

Figure 4: Generation mix of California grid under a high RPS scenario [17]**.**

The operating conditions described above would likely result in two operational situations in which traditional power production assets are used inefficiently. Both of these situations will be driven by the need to meet grid reliability concerns by having dispatchable generation online and ready to respond to grid conditions, and both may be alleviated by flexible demand-side assets, such as those in the agricultural sector. The first situation is driven by the increased share of generation from renewable resources on the grid, which increases the magnitude and frequency of events in which renewables' intermittency threatens the grid's stability. The second situation is driven by the time of day when renewable generation — specifically solar — comes online, resulting in significant needs to ramp other generation resources down or up. With higher penetration of intermittent and non-dispatchable generation sources, grid operators have less control on the generation side to ensure efficient and reliable grid operation. In response to this situation, grid operators are looking at demand as a dispatchable resource for balancing the grid. Agricultural loads, with their large magnitude (3% of California's total peak electricity demand) [20], may provide that resource.

Demand Management Markets and Policies

As discussed in the previous section, a renewable electricity grid in California is likely to result in variable, intermittent, and uncertain loads on the grid, and may complicate the optimal operation of an already complex electricity system. Several researchers have suggested that responsive load management, in the forms of TOU, DR, and AS, may provide a cost-effective method for offsetting cost implications of unpredictability of renewable resources (Kiliccote, et al., 2010). Figure 5 provides a visual representation of timescales and needs that various load management approaches, also referred to as "DR service types" can address.

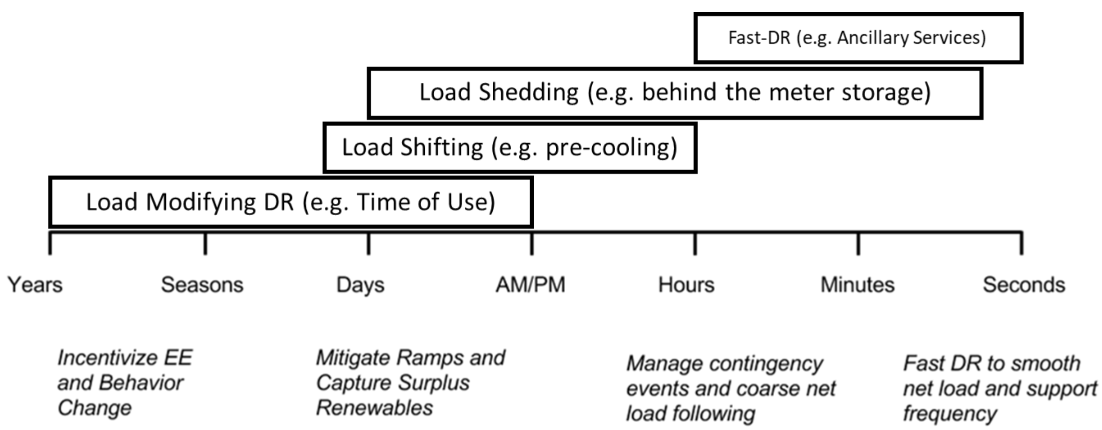

Figure 5: DR service types presented over timescales for grid dispatch frequency and/or response [15]

However, in order for those demand-side resources to provide benefits to the grid, appropriate market mechanisms and policies need to be in place. Market mechanisms are needed to coordinate electricity end users, generators, and grid operators [21]. These mechanisms would ensure that the needs of the electric grid are satisfied while entities providing services to the grid are appropriately compensated. While more intermittent renewable sources are integrated into the grid, as dictated by the renewable targets, grid operation becomes more complex, giving rise to more complicated and nascent market mechanisms [21]. In this section, we discuss the current status, potential benefits, and existing markets and policies for three load management approaches: time-of-use pricing, demand response, and ancillary services and supply side resources.

Time-of-Use Pricing (TOU)

TOU pricing aims to reshape the underlying load profile through long-duration price schdeuls that are announced months ahead of time and change seasonally. TOU rates are typically higher during peak hours (hours with highest demand for electricity) and lower during off-peak hours. To review the impacts of TOU rates, Figure 6 shows an example of TOU rates for agricultural accounts in the Pacific Gas and Electric (PG&E) territory in California.

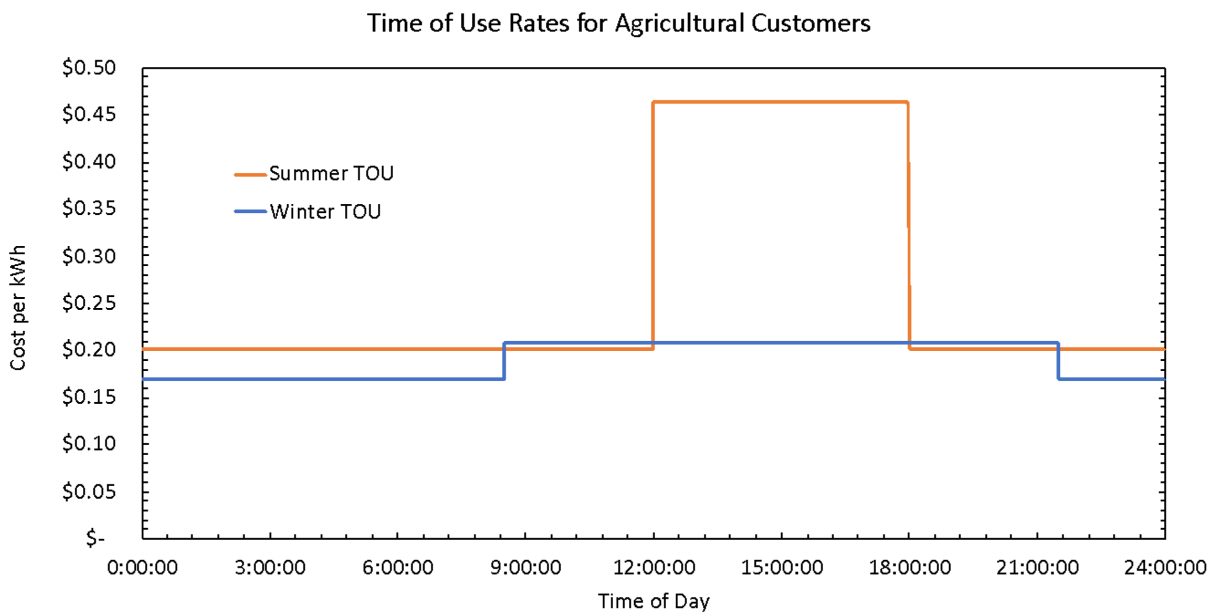

Figure 6: Time-of-Use Rates for PG&E Agricultural Customers (Based on AG4A rates per kWh 9/1/18).

TOU has historically been the most cost-effective option for modifying load shapes. A recent study conducted by Lawrence Berkeley National Laboratory (LBNL) for the California Public Utilities Commission [15] estimates that TOU pricing is particularly cost effective because few site-level technologies are required for its enablement. While the load reduction at any given site is typically small, the breadth of participation — possibly for a variety of rate schedules that currently exist — can yield substantial statewide benefits.

As highlighted earlier, because of the higher midday adoption of renewable generation (particularly solar) in California, the state's historic peak periods are now periods with the highest level of solar electricity generation (or lowest net demand). This has motivated utilities to revise their peak periods and propose shifting them to later hours in the day (3:00/4:00 pm to 8:00/9:00 pm) [22]. However, there are practical considerations with the number of TOU periods there can be, due to the need to keep rates simples for the customers. The implications of such shifts on irrigation schedules have not been studied. While agricultural users are apparently responsive to current TOU rates, it is not clear whether loads can be increased during midday to take up solar energy or to pre-irrigate the soils so pumping can be reduced during the TOU period (e.g., 4:00 pm to 8:00 pm). Both a conceptual study and a demonstration are needed to evaluate those shifts. For example, we know that with existing manual pump controls, it is also not clear whether workers are able to change pump operation outside of usual labor hours, or whether the added worker time makes it economically cost beneficial.

Demand Response (DR)

DR and Automated DR (ADR) are strategies that encourage electricity end users to shed or shift their load for economic or reliability reasons and occur with much less notice compared to TOU. DR commonly refers to strategies that are implemented manually, and ADR refers to automatic adjustment of loads based on signals received from the utility or the Independent System Operator (ISO). DR and ADR programs are often supported by third-party aggregators who act as an intermediary between the user and the utility, in this case vetting the farm's energy use history and setting up the contracts and hardware that might be required to monitor and control pumps.

Historically, DR and ADR resources have been used to reduce system-level peaks (e.g., hot summer days) [9]. However, we found limited DR/ADR participation in California's agriculture. Participation was largely limited to programs that provide hourly, or slower, load modification [21]. Moreover, they are typically operated as open-loop systems to meet broad curtailment or shifting needs, such as peak load reduction [21].

Ancillary Services and Supply Side Resources

The previous two grid resources discussed in this section, TOU and DR, are commonly referred to as *load modifying* or *demand-side resources.* The benefits of load modifying resources are that they are relatively easy to implement (e.g., using off-the-shelf hardware and software) which makes them cost effective. For example, total agricultural pumping is decreased, or pumping is shifted to different periods of the day or season. In contrast to load modifying resources, *supply side resources* refer to any resources that transact[3] directly with the ISO. These resources participate in the market by providing a bid, comprised of amount, price, and duration. The resources must participate with short (minutes) or no notification and must adhere to the same requirements as those of a power generator [21]. For example, a supply side market (e.g., ancillary services) requirement may include fast response time capability (< 1 min–10 min), secure communication protocols (e.g., OpenADR2.0b), and fast transaction settlements (5-min intervals) metering [23].

Besides limited pilot programs such as the Demand Response Auction Mechanism (DRAM) [24], there are currently no other mechanisms in place that allows customer loads to directly provide supply side DR in California.

Energy for Agriculture

[3] A *grid transaction* refers to transaction between two willing parties who enter into a physical or financial agreement to trade energy commodities. For more information about electricity grid terminology, please refer to U.S. Energy Information Administration's Electricity Glossary (EIA, 2018).

In this section we discuss how energy use is becoming an important consideration on farm operations, and how energy implications may, or will, motivate changes in irrigation schedules and plans. We also discuss whether energy costs/benefits may be a prime mover in the future for promoting improved irrigation technologies, operation decision support systems, and ultimately water resource management. An operation that was traditionally driven by crop markets may be improved by considering opportunities from the energy markets.

With more extreme weather conditions, uncertainty of surface water availability, and a switch to pressurized irrigation, volume of groundwater pumped could increase. Average energy intensity for groundwater pumping in California is approximately 500 kilowatt-hours per acre foot (kWh/AF) and can range from 250 kWh/AF to 1,000 kWh/AF [25]. The average energy intensity for surface water pumping is estimated to be 300 kWh/AF [25]. Increases in groundwater pumping will likely lead to increases in energy use for pumping, which could increase a farm's operational costs significantly. For these reasons, the energy and cost implications of irrigation is becoming a greater operation and decision consideration for farmers, to the extent that these costs factor into profitability. For example, farmers spent roughly $500 million in additional pumping costs during the 2014 California drought due to lack of surface water availability and lower water table levels [26].

Figure 7 illustrates the typical irrigation process on a farm with water and energy flows, and expresses the connections between water and energy in agricultural irrigation in California. Although these connections are discussed in various open literature, little has been presented that provides an overview from the perspective of DR management. Figure 7 illustrates a generic representation of the available assets on a farm, as well as the electricity and water flows. It does not include all possible equipment found on a farm (e.g., cold storage and electric vehicle chargers such as lift trucks).

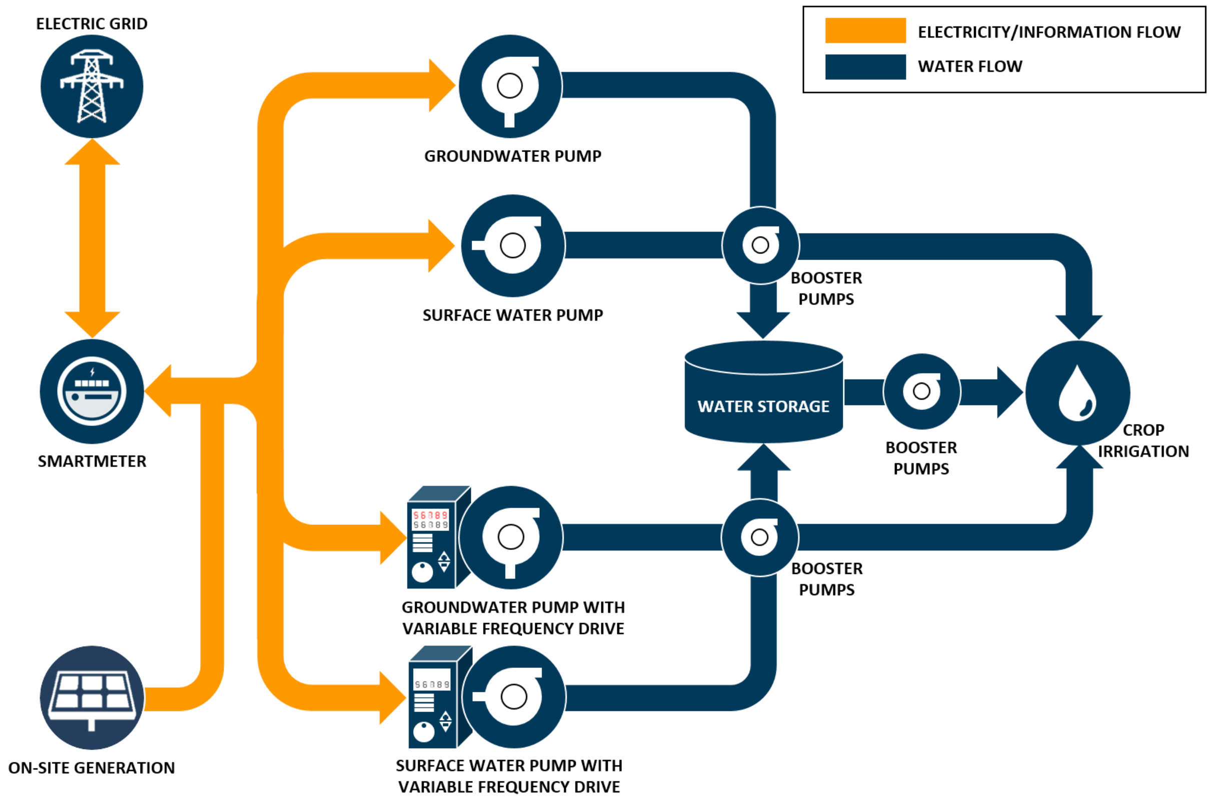

Figure 7: Illustration of possible water and energy flows on a typical farm in California. The predominant energy loads consist of groundwater, surface water, and booster pumps.

The largest energy consumers for irrigated agriculture, especially in water-scarce regions, are groundwater pumps. Surface pumps are low-static-head systems with most of the energy expended to overcome the dynamic head. Booster pumps in California use nearly two-thirds the amount of energy expended by well pumps [27]. However, unlike groundwater pumps, booster pumps must keep the water in the irrigation system pressurized, which makes them less flexible [27]. A variable frequency drive[4] (VFD) takes the electrical supply from the utility and changes the frequency of the electric current, which results in a change of motor speed. VFDs are most commonly installed for energy saving purposes; however, improved process control is another reason for installing VFDs. Their use in a broad range of farm applications, however, must still be tested.

[4] VFDs are a subset of variable speed drives (VSD), since changing the frequency of power supply is one way of controlling the pump speed. However, the term VFD is used in this report by default, as they are most commonly used by the industry.

While pumps use the majority of the electricity on the farm, other equipment and generation sources also can facilitate DR participation of agricultural pumps. That equipment includes solar panels and water storage. Presence of those components can affect the timing and manner of electricity consumption and its controllability on a farm. To take full advantage of available loads on farms, it is necessary to characterize their DR potential, level of automation, response time (in seconds, minutes, or hours), and required notification time. In the last section of this paper we present an illustrative example of the AS potential of California farms, assuming various levels of VFD adoption under different scenarios.

Water for Agriculture

A recent study by researchers at the University of California (UC), Davis, estimates that approximately 70% of energy used on farms is expended for moving water [27]. This energy is used largely by the pumps shown in Figure 7. To understand and quantify DR opportunities, sources of water, timing of its use, and its energy intensity need to be presented. The California Water Atlas provides a broad view of the conveyance of agricultural water in California, and the United States Geological Survey (USGS) estimates the energy impacts of water conveyance. Approximately 80% of the nation's consumptive water use is for agriculture, and in Western drought-prone states that number increases to 90% [2]. In Western states, irrigation provides most of the crop water requirements, while in Eastern states, irrigation is largely supplemental [28]. Figure 8 below shows the makeup of typical pumping practices. Surface water pumping is often constant throughout the year, with groundwater pumping peaking during the summer months. Moreover, with a trend toward increased reliance on groundwater, the energy peaks during these summer months may become more pronounced, suggesting higher DR potential in the near future.

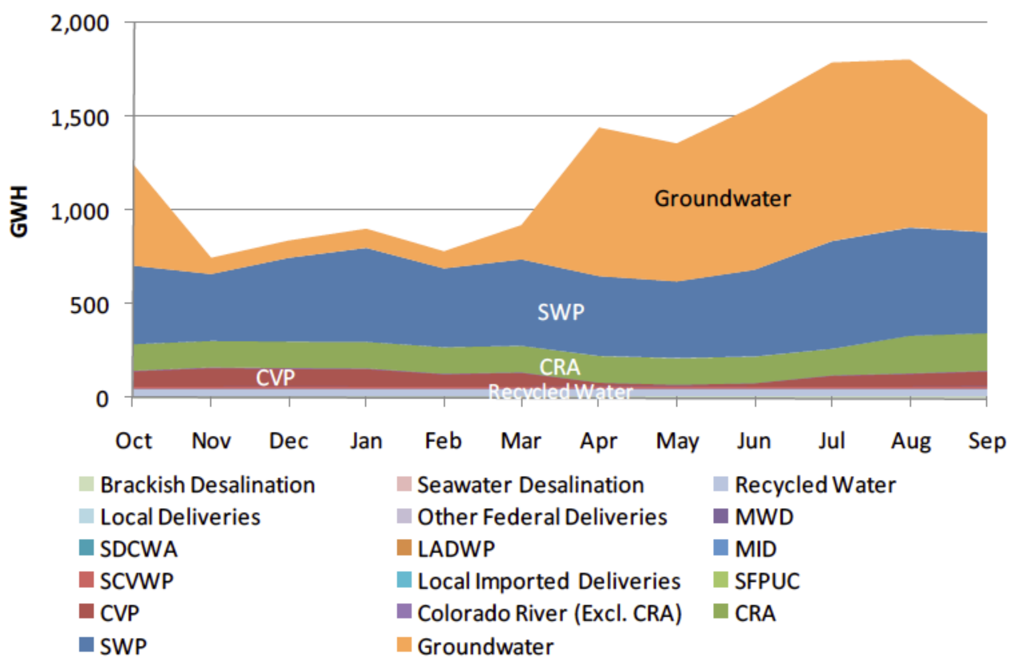

Figure 8: Baseline Monthly Energy Profiles of Statewide Water Delivery Operations[5] [29]**.**

Trends in Agricultural Irrigation

Historically the focus of all agricultural operations has been on maximizing yield [30]. According to English (2015), maximizing yield is synonymous to maximizing revenue. Thus, infrastructure development and research has focused heavily on developing irrigation schedules and models of crop growth for various external conditions to increase total crop yield. This approach to crop management has resulted in a traditional method of designing irrigation schedules that are based according to the conditions of crop, the soil, and the scheduling of worker availability. This legacy approach to crop management exposes farms to risks such as water availability, reliability of electric service, electricity prices, and environmental impacts (e.g., water quality, groundwater salinization, and land subsidence) [31].

Recently, the United States Department of Agriculture (USDA) estimated that 23% of California farms are using, or are moving toward, a more “smart” irrigation approach, using one or a combination of plant or soil moisture sensing devices and/or computer simulation models

[5] Figure abbreviations: San Diego County Water Authority (SDCWA), Santa Clara Valley Water District (SCVWP), Central Valley Project (CVP), State Water Project (SWP), Los Angeles Department of Water and Power (LADWP), Metropolitan Water District of Southern California (MWD), Modesto Irrigation District (MID), San Francisco Public Utilities Commission (SFPUC), Colorado River Aqueduct (CRA)

to predict the amount of water delivered to crops [32]. In this most recent study, however, the focus of these emerging approaches toward irrigation scheduling still focused on maximizing crop yield. Little consideration or discussion was given to energy costs (or opportunities), water value, and/or water availability. English et al. (2015) discuss emerging practices for optimizing irrigation to improve water use and crop development. Though promising, the transition toward irrigation cycles based on local water needs is still slow.

Agricultural Pumping and the Grid

As discussed in earlier sections, agricultural loads have the potential to meet the future grid challenges highlighted in Figure 3. Lawrence Berkeley National Laboratory's most recent assessment of DR potential in California [15] estimates DR potential and valuation, grossly, for the major load sectors, and reports on an aggregated assessment of agricultural loads. In it, the study assumed that the primary load end use in the agricultural sector is the electrical pumping required for irrigating crops. With utility-provided hourly data, they estimated that 80% of an agricultural customer's load is from pumping at all hours of the year [15]. While this is likely a coarse assumption, the resulting estimates provide an overall view of the magnitude of the agricultural loads in California. The following paragraphs summarize some of the findings from previous LBNL demand response studies.

In 2016, the peak demand of the California's electricity grid was recorded to be 46 gigawatts (GW) [20]. In the same year, the peak demand for agricultural irrigation pumping was 1.3 GW (3% of California's total peak electricity demand) [1]. As of 2015, the California Investor Owned Utilities' (IOUs') total DR portfolio added up to approximately 2.1 GW [9]. Thus, it is theoretically feasible that 62% of the current IOU demand response portfolio can be satisfied through agricultural irrigation DR alone. Moreover, as highlighted in the previous section, the seasonal peak irrigation demand aligns significantly with peak solar generation, and in the absence of inexpensive battery storage, it is possible that excess generation can be used to pump water into holding/irrigation ponds or to increase soil moisture to upper limits [33].

One of the challenges, and thus opportunities, with a high renewable penetration grid, is the steep ramping of net load during the shoulder periods of the day, typically hours of 4:00

PM-7:00 PM [15]. A recent study estimates that California farms consume about 3 gigawatt-hours (GWh) of energy during those three hours (4:00 PM-7:00 PM) [1]. California's current installed pumped storage capacity is 3.1 GWh, with 1.3 GWh of additional storage set to be deployed by 2020, per the state mandate [24]. This suggests that California farms have the technical potential to shift all their pumping loads from evening hours (4–7 pm) to midday hours (when excess solar generation occurs). If agricultural load shifting is accepted as an alternative to energy storage, employing such a strategy, could double California's energy storage capacity and help the state meet its mandated energy storage requirements.

Presently, agricultural loads have limited access to the necessary market mechanisms that would enable them to provide resources to the electricity grid [33]. The most recent rulemaking by the CPUC enables two market mechanisms or pathways for DR to provide services to the grid: (1) load modifying resources (demand-side), and (2) supply resources. As of now, according to CPUC rules, farms can only provide demand-side DR resources to the grid.

Figure 9 shows the total hourly crop load for California's three IOUs in 2014. Demand varies throughout the first months of the year and steadily climbs to a peak in the summer before decreasing through the fall. Figure 10 shows the same data but only for March and June, where daily and weekly patterns can be observed; there is a daily peak each morning except for Sundays.

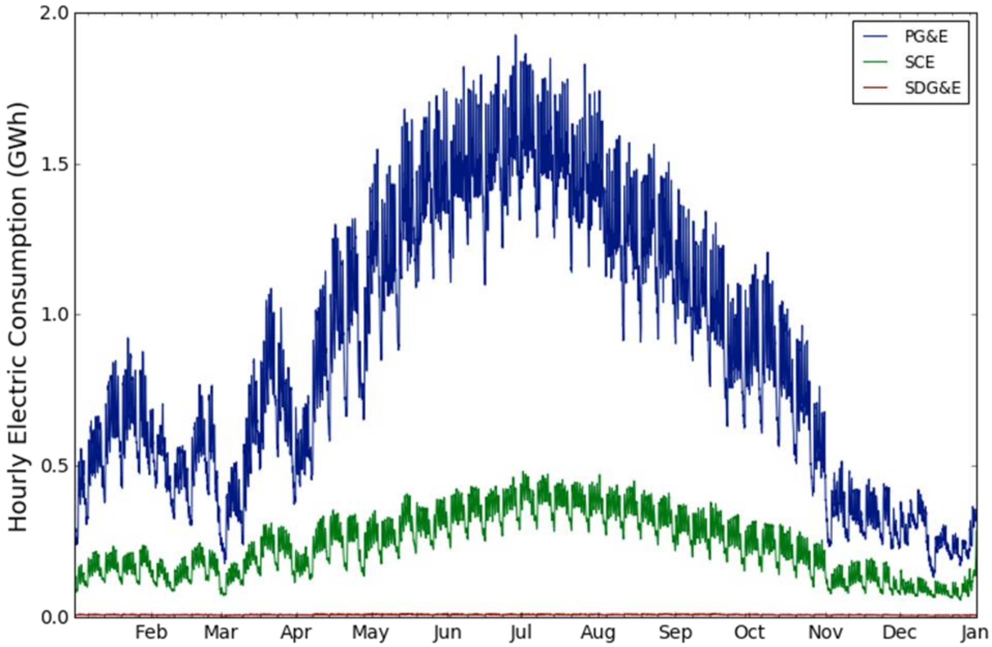

Figure 9: Hourly "Agricultural – Crop" electricity use for California's three investor-owned utilities for 2014. Data from DR Potential Estimation Package (DR Futures) v1.0, LBNL. San Diego Gas & Electric's (SDG&E's) load is very small and therefore hardly visible.

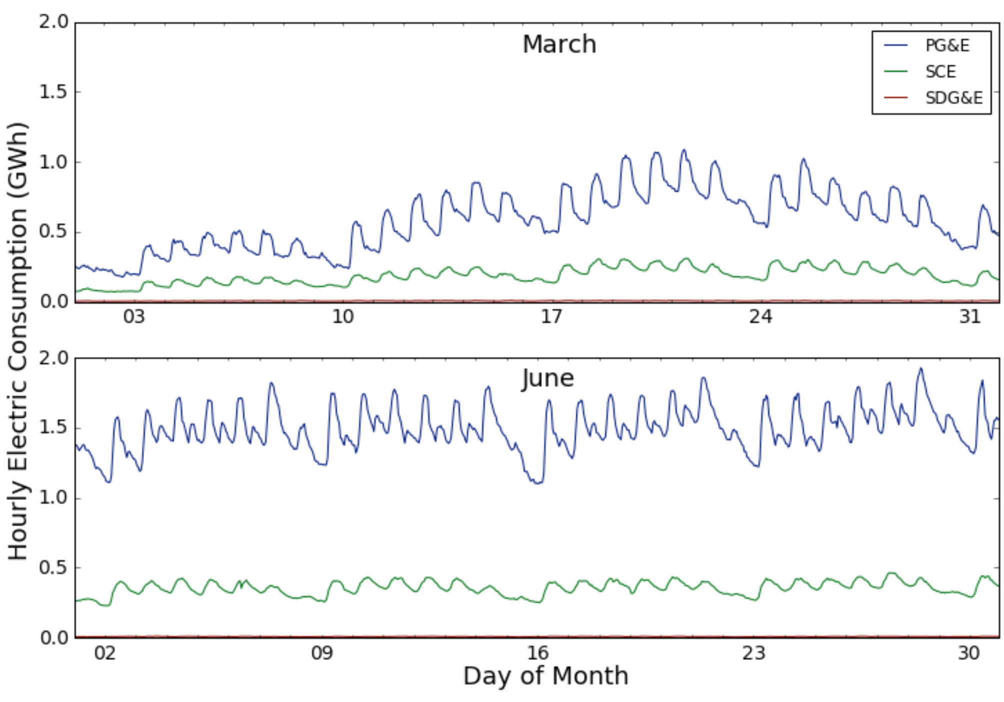

Figure 10: Hourly agricultural electricity use for California's three investor-owned utilities for March and June 2014. Data from DR Potential Estimation Package (DR Futures) v1.0, LBNL. SDG&E's load is very small and therefore hardly visible. X-axis ticks represent Mondays.

Daily and monthly patterns are examined further in Figure 11, which shows PG&E's agricultural sector total load each day of 2014, separated by month. There is a consistent, albeit small, decrease in load from approximately noon until 6 pm from May to September. The decrease corresponds very closely to changes in peak retail prices for agricultural customers on TOU rates in 2014 [34].

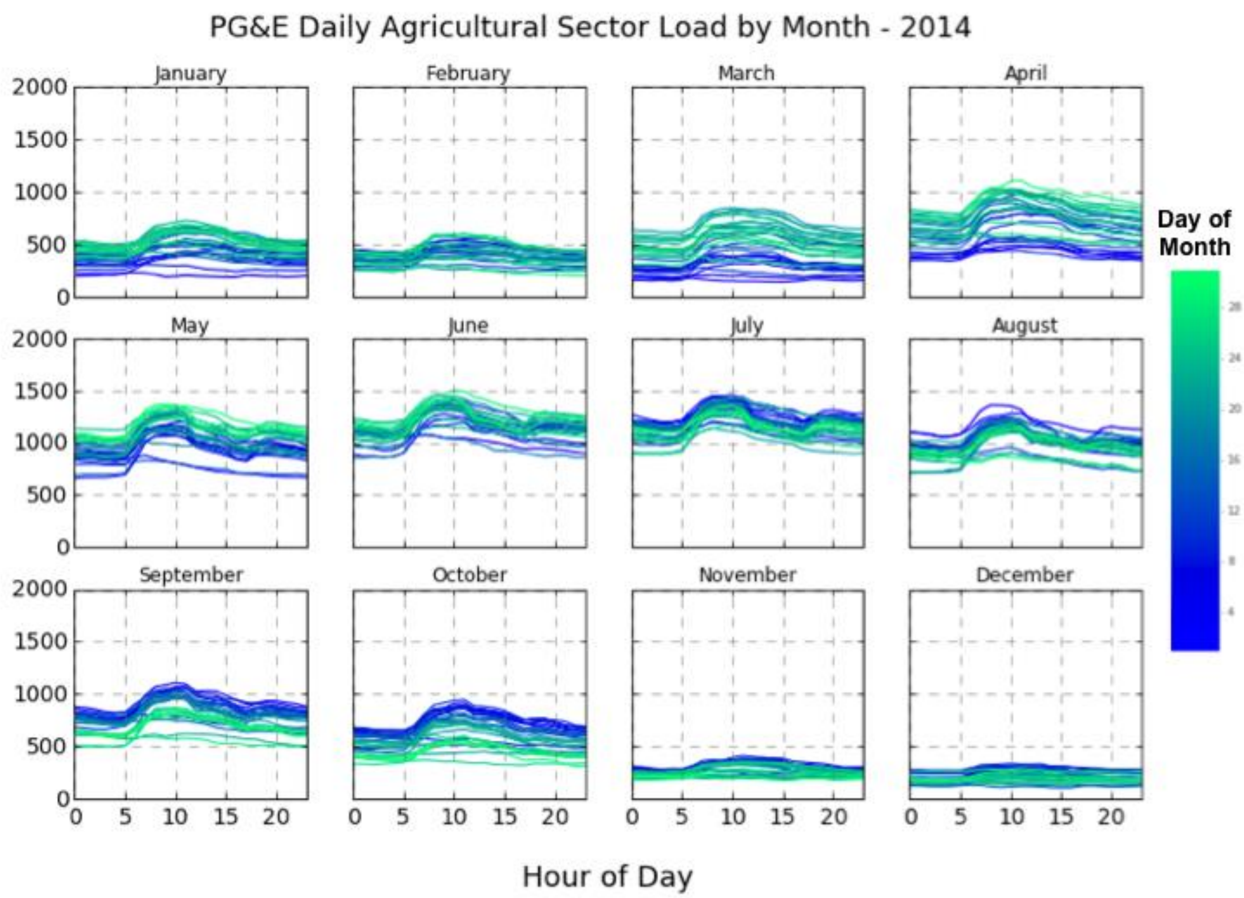

Figure 11: Monthly plots of daily agricultural load variability in PG&E. Each line indicates a different day of the month.

Figure 12 shows average daily demand profiles recorded by PG&E's SmartMeters. The period of TOU pricing indicates the degree to which farms are participating in load modifying programs today. With 60% of all growers in California taking part in some form of TOU scheduling, this is by far the most widely used demand management program in agriculture [35]. Figure 12 reinforces that growers are responding to moderate price differentials in their electricity tariffs and actively shifting load from afternoon hours to the morning, with most daily peaks occurring before 10 am. In short, even without much pumping automation, we see notable changes in pumping behavior during the typically high pumping season.

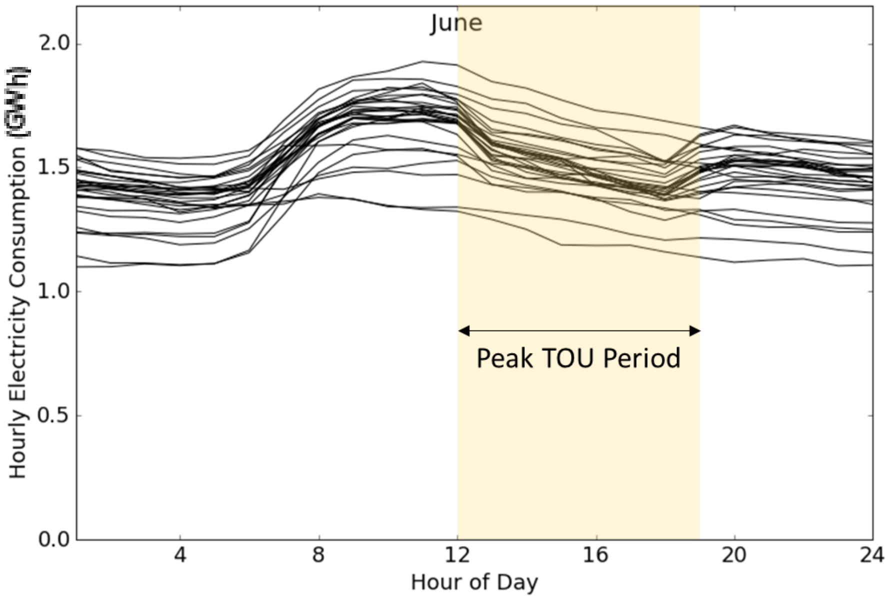

Figure 12: Plot of hourly agricultural load in PG&E's territory for each day in June 2014. In June 2014, most electrical tariffs for PG&E's agricultural customers were TOU rates with on-peak prices from 12 pm–-6 pm. All hours represent an "hour ending" measurement.

Figure 13 shows daily average agricultural loads by month for a subset of PG&E customers. There is a daily load profile with some diurnal variation, where loads are above average from approximately 7 am–4 pm (peaking about 15% higher), and below average during the rest of the hours (with a minimum of about 15% lower) [1]. Higher-than-average peaks coincide with hours during which solar power generation exists (7 am to 4 pm). Figure 13 shows the average daily demand profile of a subset of PG&E's agricultural customers over 10 years: 2003–2012. To generate Figure 13, Olsen et al. started with a list of 106,501 agricultural customer accounts in the PG&E territory and then filtered out customers with uncertain location, overly general or explicitly non-crop accounts, fewer than 12 months of data, and those who averaged less than 1 kilowatt (kW) of demand in the previous year. The resulting subset of agricultural accounts used to generate Figure 13 contained 24,385 meter readings. Figure 13 highlights the synergies between the need (mitigating the duck curve) and the resource (agricultural pumping loads).

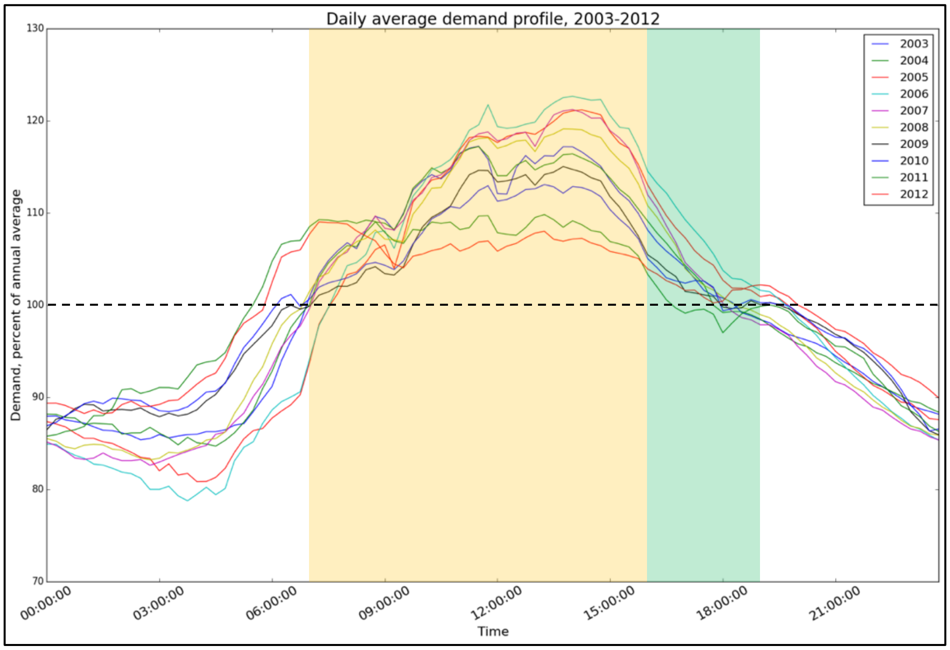

Figure 13: Synergies between the agricultural pumping demand and the net load of California grid

According to daily agricultural load profiles, a substantial amount of pumping (roughly 3 GWh) occurs between the hours of 4 pm–7 pm: the period with the steepest ramp requirement. Side-by-side analyses of Figure 4 and Figure 13 result in various scenarios where pumping loads, if technologically enabled with hardware and controls, may meet many forms of DR resources. For example, one scenario would be to shift pumping from evening hours (highlighted in green) to midday hours (highlighted in yellow). Such a scenario could assist in shifting the shape of the duck curve by reducing renewable curtailment during the day and reducing the shape of the generation ramp requirements in the evening.

In our review of utility programs in the Western United States, agricultural customers can only provide resources to the grid by enrolling in a TOU tariff, DR, or ADR program offered by their local utility or through a third-party aggregator. Several utilities, including PG&E, Southern California Edison, Idaho Power, Rocky Mountain Power, Midwest Energy, NV Energy, and Golden Spread Electricity Cooperative offer limited DR programs tailored toward agricultural irrigation customers with a combined load shed magnitude of 0.7 GW dating back to 2004 [1]. Although largely successful, challenges faced by current agricultural DR programs include unreliable shed rates (35%–85% relative to baseline load) and low participation[6] rates (20%). These are largely owing to a lack of automation, communications, and controls, as well as farm operational limitations (irrigation capacity, water delivery schedules, and labor)[1].

In the future, it is conceivable that fast responding DR services participating directly into supply side markets will become more available and viable for the agricultural industry. ADR also has the potential to enable AS, which are growing in importance due to the aforementioned load uncertainty and variability concerns [36].

In the next section, we document potential load shed and financial benefits of AS participation under different enabling technology scenarios (various levels of VFD penetration). Although estimates of TOU and DR potentials for the agricultural sector are present in literature, no such analysis has been conducted to document the technical potential of AS participation in irrigated agriculture.

[6] *Participation rate* refers to the number of customers who provided load shed during a DR event, divided by the number of customers enrolled in a DR program.

An Illustrative Example of Assessing Technical Potential for Ancillary Services

In this section, we explore the technical potential for ancillary services if opportunities for providing ancillary services through agricultural irrigation pumping loads in California existed. As discussed earlier, a significant challenge facing the California grid is the potential development of the duck curve. In other words, there is a desire for the grid to be responsive to loads that are capable of ramping up (to avoid solar over generation) or ramping down (to address the evening peak) with short notification periods. Services that can quickly ramp up or down to maintain grid stability are commonly referred to as *ancillary services.* To our knowledge, none of the existing DR programs offered through the utilities address this need currently. Ancillary services are an underserved and understudied resource, especially within the agricultural sector. Therefore, it is important to quantify the technical potential that California agriculture can provide for the ancillary services market, so that utilities, regulators, and other stakeholders can help to enable this sector to provide this important resource. The purpose is to estimate the magnitude of potential for a technology that may, to a limited extent, become viable on farms, and if so, estimate the resulting opportunity. The approach is based on a recently developed method for computing DR potential [15]. We emphasize the estimation below as illustrative of the type of computations, the data, and the technological information needed for future quantitative energy assessments.

Variable frequency drive equipment is becoming more readily available in the marketplace. Its application for farm pumping has not been tested in great detail, and the degree to which it can be used for various pumping needs, such as groundwater, surface, and booster pumping, is still in question. These drives can, however, be retrofit onto many existing three-phase electrical pumps, and their use could in theory enable farms to participate in a wide range of DR resources. In this section we explore the amount of load that could be enabled for ancillary services.

To quantify AS, one must consider the fraction of existing pumping energy that can be supplied by VFD systems and the portion of the VFD-enabled pump load that is available for AS. No data exists upon which to estimate VFD-enabled pumping availability for AS. Thus, we considered the upper and lower bounds using our best engineering judgment. We assumed a lower bound of 25% would represent a likely achievable market penetration and an upper bound of 100% would represent the full potential of the agricultural pumping resource. These bounds are consistent with the range of penetration of newer technologies in industry.

The fraction of the load that is available for AS is referred to as a *flexibility factor.* However, at the time of this analysis, AS is not available for farms in California, and AS performance requirements and attributes have not been codified. Therefore, we considered similar performance requirements, such as the metrics used to describe load-shedding demand response. Killiccote et al. (2010) showed possible attributes based on their review of wholesale markets in the United States; these are shown in Table 1 [37].

Table 1: Performance requirements of ancillary services in the California ISO's markets, as well as whether or not proxy demand resources (PDRs) or non-generating resources (NGRs) are eligible for participation in these markets as of 2017. Agricultural pumping has been demonstrated as a PDR resource, but not an NGR resource; however, the inherent flexibility in soil water storage may allow for irrigation pumping to act as an NGR. Additionally, other markets, such as the PJM regional transmission organization, have demonstrated frequent use of DR resources for regulation, indicating that barriers are not technical, but the result of market rules.

Ancillary Service	Reason for Dispatch	Response Speed	Bid Duration	PDRs Eligible?	NGRs Eligible?
Regulation Up	System frequency is too low (i.e., supply is less than demand)	4 seconds	15 min.	No	Yes
Regulation Down	System frequency is too high (i.e., supply is greater than demand)	4 seconds	15 min.	No	Yes
Spinning Reserves	Transmission or generation outages	Instantaneous start, ramp to maximum in 10 minutes	2 hrs.	No	Yes
Non-Spinning Reserves	Transmission or generation outages. Dispatched after spinning reserves.	Ramp to maximum in 10 minutes	2 hrs.	Yes	Yes

The U.S. Department of Energy's *Demand Response and Energy Storage Integration Study* estimated that shedding 100% of pumping load is reasonable for contingency (spinning and non-spinning reserves), capacity, and energy-type products [38]. A more recent assessment of ADR in the agricultural sector found that existing DR programs for irrigation regularly see shed rates between 50%–100% of the entire site's load [1]. The 2025 California Demand Response Potential Study estimated 70%–80% shed rates of pumping load were possible for both long-duration sheds and fast-response services like load following and regulation [15]. For this analysis, interviews with growers and irrigation experts indicated that large short-term fluctuations in load could overstress irrigation systems, decreasing equipment lifetime and increasing the likelihood of operational problems. However, these experts observed that short-term fluctuations in pump load on the order of 10%–20% would likely be acceptable, especially if such fluctuations were approximately energy-neutral over the course of the day. Accordingly, we estimate flexibility factors of 0.1–0.25 for regulation up, 0.1–0.2 for regulation down, and 0.75–1.0 for spinning and non-spinning reserves, as shown in Table 2.

Table 2: Flexibility fractions for agricultural irrigation pumping, which represent the fraction of a pump's instantaneous load available to provide various ancillary services (AS).

Ancillary Service	f_{AS}	
	Min	Max
Regulation Up	0.10	0.25
Regulation Down	0.10	0.20
Spinning Reserves	0.75	1.00
Non-Spinning Reserves	0.75	1.00

Illustration of Revenue Potential from Participation in Wholesale Markets

The California Independent System Operator (CAISO) operates wholesale markets for the provision of both energy and ancillary services across much of California and a small part of Nevada. The AS markets include Regulation Up, Regulation Down, Spinning Reserves, and Non-Spinning Reserves. All of these markets have both day-ahead and real-time components, with the majority of activity in the day-ahead market [39]. We assumed that day-ahead market prices are a reasonable approximation of the market prices DR would see when participating in AS.

Figure 14 to Figure 17 show hourly 2014 prices for the day-ahead markets for regulation up, regulation down, spinning reserves, and non-spinning reserves, respectively. Regulation-up prices, shown in Figure 14, have significant seasonal variation. January and February have relatively low prices; March through May have slightly higher prices, with two diurnal peaks at 8 am and 8–9 pm; June through September have a single diurnal peak that builds from noon until 6–7 pm; and October through December have two diurnal peaks, similar to the spring, but with much higher prices during the evening peaks. An explanation of these prices are beyond the scope of this paper; see CAISO (2016) for further discussion.

Regulation-down prices (Figure 15) are generally lower and steadier than those of regulation up prices, and they show a distinct seasonality in 2014. February through June have high prices and large variability in early morning hours, with other months having no daily patterns and relatively steady prices, at < $5/megawatt. Spinning reserves, shown in Figure 16, have similar seasonality and diurnal patterns to regulation up prices, with two diurnal peaks in spring and winter, and a single later afternoon peak during the summer. However, there are many periods throughout the day when the market value of these services is zero. Lastly, Figure 17 shows that non-spinning reserve prices on the day-ahead market in 2014 were extremely low; approximately zero for most hours of the year. However, there are higher-price hours in the late afternoon and early evening.

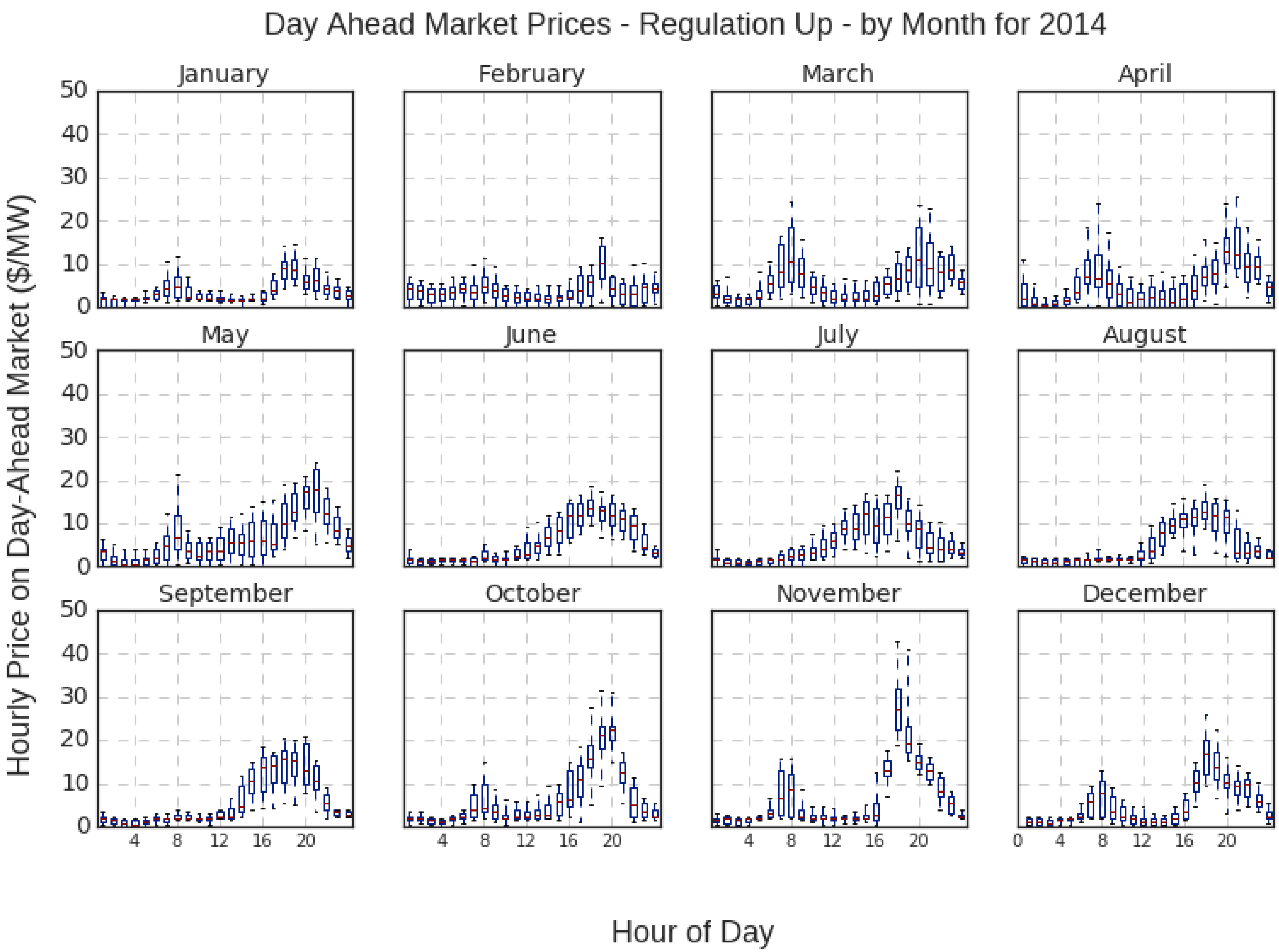

Figure 14: Historical day-ahead market prices, by month, for a Regulation Up scenario in the California ISO. The red centerline represents the median price of each hour, boxes represent 25th and 75th percentiles, and whiskers represent 5th and 95th percentiles.

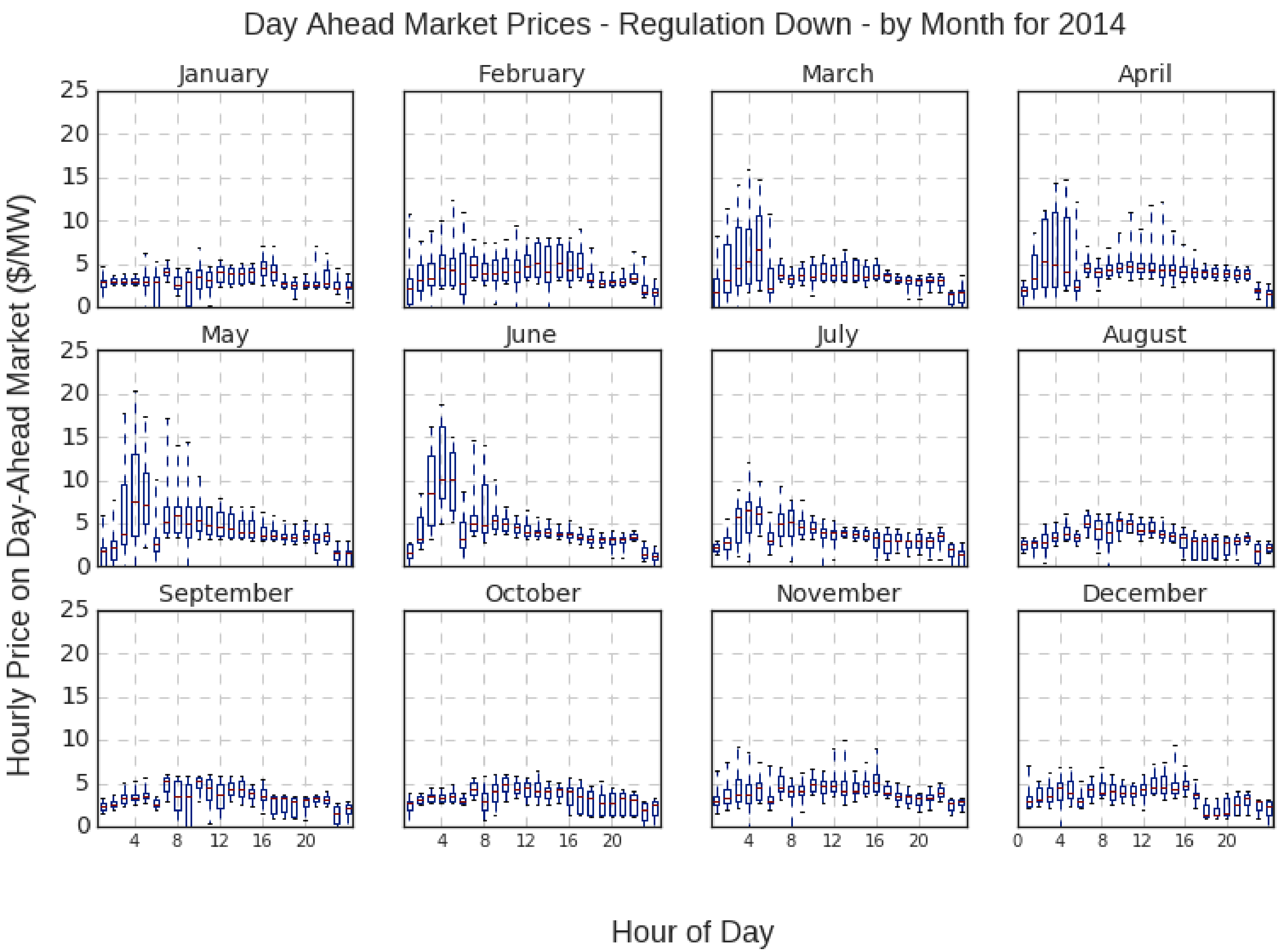

Figure 15: Historical day-ahead market prices for a Regulation Down scenario in the California ISO. The red centerline represents the median price of each hour, boxes represent 25th and 75th percentiles, and whiskers represent 5th and 95th percentiles.

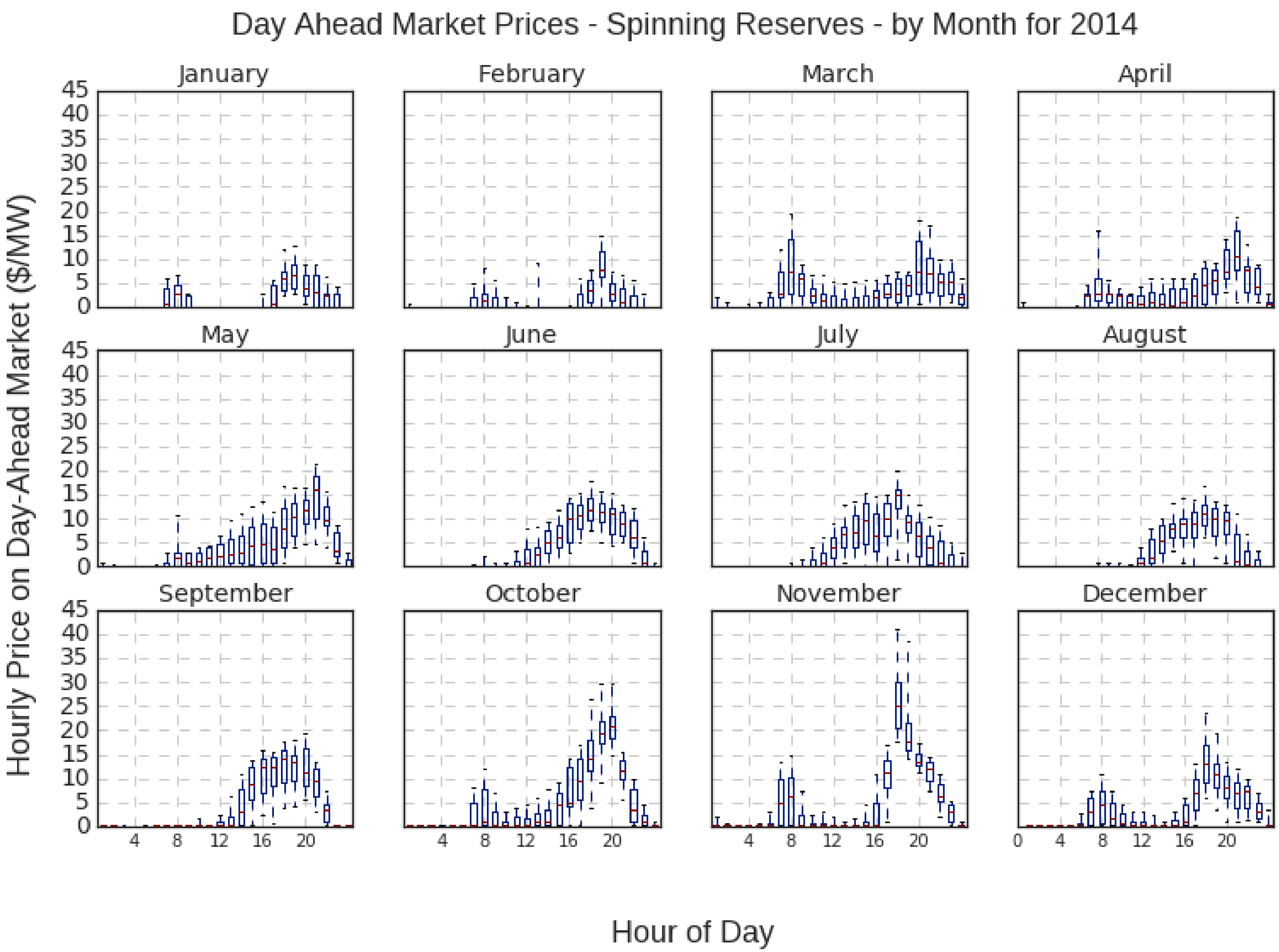

Figure 16: Historical day-ahead market prices for A Spinning Reserves scenario in the California ISO. The red centerline represents the median price of each hour, boxes represent 25th and 75th percentiles, and whiskers represent 5th and 95th percentiles.

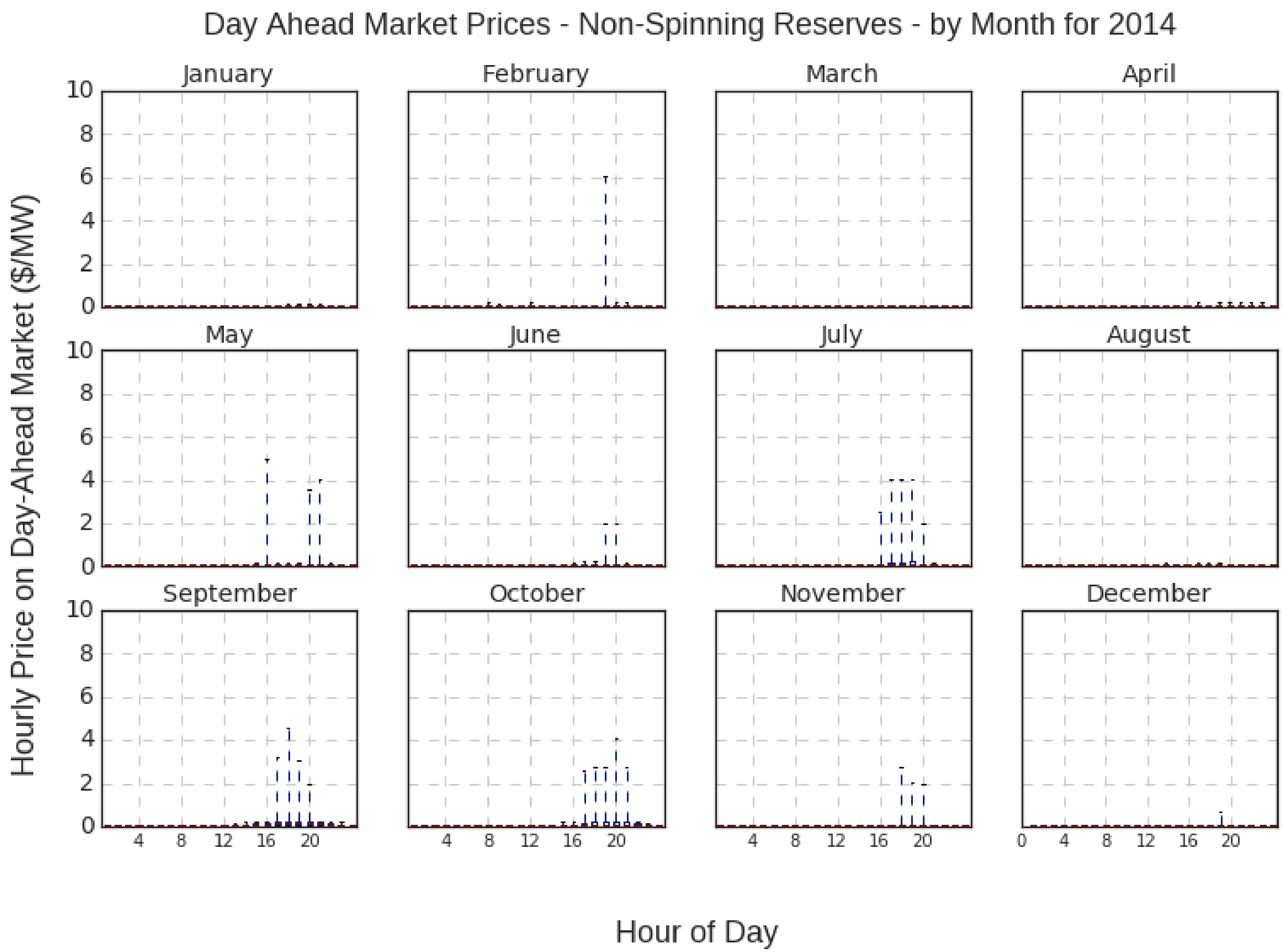

Figure 17: Historical day-ahead market prices for a Non-Spinning Reserves scenario in the California ISO. The red centerline represents the median price of each hour, boxes represent 25th and 75th percentiles, and whiskers represent 5th and 95th percentiles.

With the above information, we were able to compute hypothetical revenues earned through AS market participation according to Equation 1, where total annual revenue in a given market (R_m) is merely the sum of the quantity of energy bid into the market that hour ($E_{m,t}$) and the hourly product of the AS market price ($P_{m,t}$). Equation 1 assumes no price elasticity of supply, thus it represents an upper bound estimate.

Equation 1 $$\boldsymbol{R_m = \sum_{t=1}^{8760} E_{m,t} P_{m,t}}$$

To explore how this revenue potential would develop and be affected by California's renewable energy goals, we developed scenarios for the year 2025 based on possible market changes that may be required to support a high penetration of renewable energy sources. Figure 18 shows CAISO's average daily procurement costs for ancillary services in 2016.

From late February to June, CAISO doubled the regulation up and down reserve requirements "in response to growing needs for regulation to balance variable renewable generation" [40]. We developed two hypothetical scenarios for 2025, one where regulating reserve requirements are increased to 150% of 2014 values, resulting in a doubling of regulation prices, and one where regulating reserve requirements are increased to 200% of 2014 values, resulting in a tripling of regulation prices. We assumed that higher penetration of renewables will not affect contingency reserve (spinning and non-spinning) requirements [38], therefore we assumed those prices remained the same as 2014.

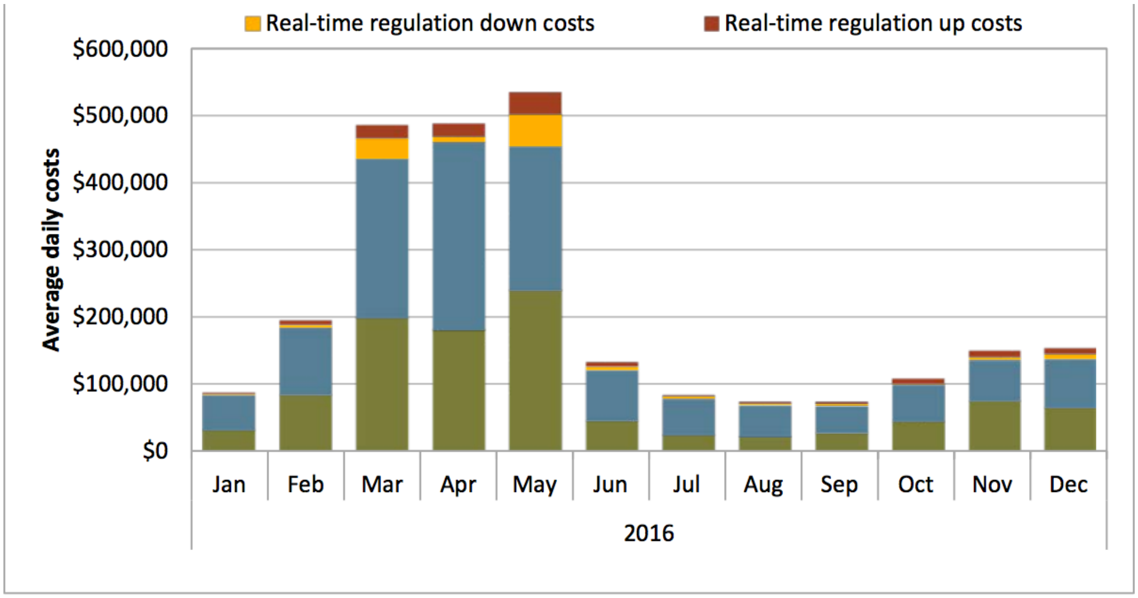

Figure 18: Average daily regulation procurement costs for California ISO markets in 2016. In February, the CAISO doubled their regulation requirements, resulting in a three-fold increase in prices. In June, the CAISO relaxed their regulation requirements back to pre-February levels, resulting in lower prices.

For 2014, results show that California's agricultural irrigation could, in theory, have provided 4%–10% of the regulating reserves requirements, and 12%–16% of either spinning or non-spinning reserve requirements, assuming that VFD-enabled pumps existed on all farms. If 100% of California pumps were enabled with VFDs, approximately 25% of regulating reserves requirements and 75% of either spinning or non-spinning reserves requirements could have been supplied. These results are summarized inTable 3. It is important to note that these estimates are hypothetical, since no mechanism exists for allowing direct participation of agricultural loads into ancillary services markets. Also, ancillary services markets are relatively untapped, and the value of AS resources are expected to decline over time as more end loads enter the AS market.

Table 3: Potential revenues from AS market participation for agricultural irrigation in 2014, as well as the fraction of AS requirements agricultural irrigation could meet. Revenues assume single-market participation and are nonadditive.

Ancillary Service	VFD Penetration = 15%		VFD Penetration = 100%	
	Estimated Revenue ($M)	Estimated % of AS Requirements	Estimated Revenue ($M)	Estimated % of AS Requirements
Regulation Up	0.64–1.61	4–10	3.57–8.92	22–54
Regulation Down	0.46–0.92	4–8	2.55–5.11	23–45
Spinning Reserves	3.08–4.11	12–16	17.1–22.8	65–87
Non-Spinning Reserves	0.14–0.18	12–16	0.75–1.0	65–87

Results for 2025 are shown in Table 4 (where regulation requirements have increased 50% from 2014) and Table 5 (where they have increased 100%). In the 25% VFD case, we see that irrigation DR is capable of providing 4%–12% of the regulating reserves requirements and 22%–29% of either spinning or non-spinning reserve requirements. The 100% penetration case is used to demonstrate the possible resource size given ambitious retrofit and replacement programs across California's agricultural sector. In this case, we see agricultural irrigation DR technically capable of providing 12%–40% of the regulation reserves requirements and as much as 99% of either spinning or non-spinning reserves requirements.

Table 4: Potential revenues from AS market participation for agricultural irrigation in 2025 with a moderate (50%) increase in regulation requirement, as well as the fraction of AS requirements agricultural irrigation could meet. Revenues assume single-market participation and are nonadditive.

Ancillary Service	VFD Penetration = 25%		VFD Penetration = 100%	
	Estimated Revenue ($M)	Estimated % of AS Requirements	Estimated Revenue ($M)	Estimated % of AS Requirements
Regulation Up	2.42–6.04	5–12	8.18–20.4	17–41
Regulation Down	1.72–3.46	5–10	5.84–11.7	17–35
Spinning Reserves	5.77–7.7	22–29	19.6–26.1	75–99
Non-Spinning Reserves	0.25–0.34	22–29	0.86–1.14	75–99

Table 5: Potential revenues from AS market participation for agricultural irrigation in 2025 with a significant (100%) increase in regulation requirement, as well as the fraction of AS requirements agricultural irrigation could meet. Revenues assume single-market participation and are nonadditive

Ancillary Service	VFD Penetration = 25%		VFD Penetration = 100%	
	Estimated Revenue ($M)	Estimated % of AS Requirements	Estimated Revenue ($M)	Estimated % of AS Requirements
Regulation Up	3.63 - 9.06	4 - 9	12.27 - 30.66	12 - 31
Regulation Down	2.58 - 5.19	4 - 8	8.76 - 17.52	13 - 26
Spinning Reserves	5.77 - 7.7	22 - 29	19.55 - 26.07	75 - 99
Non-Spinning Reserves	0.25 - 0.34	22 - 29	0.86 - 1.14	75 - 99

Discussion

California's electricity and water systems are undergoing unprecedented changes (e.g., a 100% renewable grid by 2045 and the Sustainable Groundwater Management Act) and are in need of a new management paradigm. Water and energy use on farms are deeply linked, and their linkages are likely to increase in the future. In California, linkages are particularly apparent for its agricultural sector because of its high water and electricity use. Diminishing water availability and increased reliance on groundwater pumping are likely to increase future energy intensity. As the industry grapples with various future scenarios, it is important to understand the broad implication of water, energy, and technology trends that are emerging, and whether decisions made to improve irrigation reliability (through precision irrigation) may have deleterious effects on, and/or benefits for, the energy sector. To better understand these future scenarios, we have described the broad drivers of them in this paper. While some of this knowledge is present in various agricultural management literature, most reports provide limited commentary on the energy implications.

Agricultural irrigation pumping is a significant resource that can provide DR services to the grid and contribute to its stability. Several years of agricultural DR research has identified that successful DR participation in the agricultural sector is complex. Moreover, technological breakthroughs in the agricultural sector have traditionally focused on yield increase and crop quality improvement [30], and little attention has gone toward other operational aspects of the farm, including irrigation energy and water management. There are some indications that irrigated agriculture is moving toward a new management paradigm based on an economic objective that not only includes yield but also accounts for water, energy, and labor requirements [30].

Existing DR programs need to be modified to consider modifications that better address the evolving needs of the evolving grid. DR programs were initially designed to address challenges presented by hot summer days, not solar overgeneration. Also, many existing DR programs were designed for commercial and industrial customers, not agricultural customers. For irrigated agriculture to participate successfully in current or future programs and provide value both to the grid (as change in demand) and the farm (as financial incentives), several barriers need to be overcome. Those barriers include lack of automation, irrigation timing and system constraints, and DR program complexity.

Conclusion

In this study we identified that on-farm energy use is an increasingly important cost that variable irrigators must balance against their water availability, yield targets, and production schedules. Declining surface water and lower water tables in many Western states, as well as adoption of precision irrigation, are increasing the energy intensity (and therefore the cost) of irrigation. As the electricity grid evolves to include more distributed sources of energy generation, it needs flexible loads to maintain stability. Agricultural loads, with their large (and growing) magnitude and uniformity, have the potential to satisfy a significant portion of that critical resource.

California is experiencing an increase in extreme weather events, sustained drought periods followed by higher-than-average rainfall. The degree with which growers are making infrastructure decisions to maximize their availability of water is well understood. However, the impacts of those decisions on the electricity grid are not well known. In fact current decisions may be counter to long-term practices.

Moreover, managing pumping demand at farms may provide valuable, and thus economically viable, resources to the electricity grid in the form of responsive load management, including DR. The potential of farms to deliver on this promise relies on their large magnitudes and potential for shifting and ramping loads at the many timescales required by the electricity grid.

Additionally, load-modifying resources, in the form of TOU programs, historically has been the most cost-effective option for modifying load shapes, and may contribute substantially to overall agricultural DR opportunities. These programs have existed for farms in California for several years. On the other hand, despite the large DR/ADR and AS technical potential that irrigation pumping has to offer, participation has consistently been low or non-existent (in the case of AS). Lack of automation and other enabling technologies on farms, complexity of utility programs, the evolving nature of the grid, and the absence of necessary market mechanisms are some of the most important barriers in achieving the full grid benefits from agricultural loads in California.

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