Energy solutions for a changing world

Teaching the "Duck" to Fly

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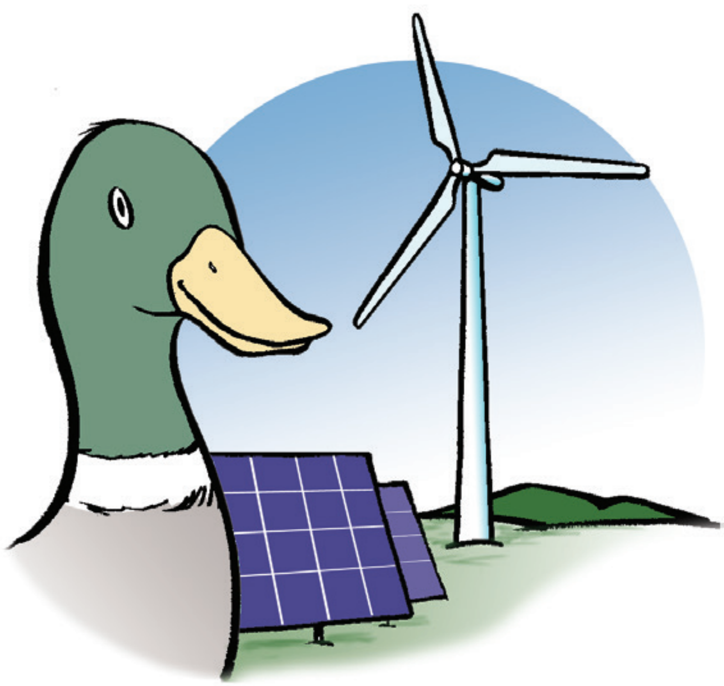

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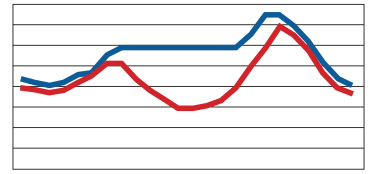


Teaching the "Duck" To Fly

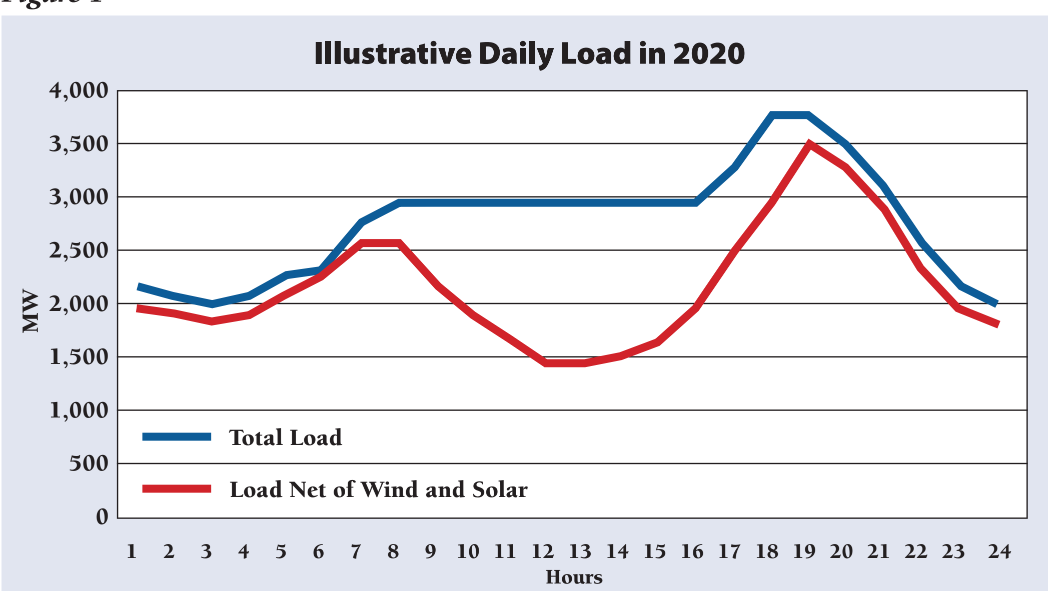
The electric sector has become very sensitive to the load shape of emerging utility requirements as increasing penetration of wind and solar energy creates challenging "ramping" issues for conventional generation in the morning and evening, when renewable energy supplies wax and wane.

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, while the renewable energy revolution is creating new challenges in a much shorter period of time. Fortunately we have technologies available to us that our great-grandparents did not.

Addressing this problem will require a change in the way utility power supply portfolios are formulated. 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.

What is now being referred to as "the Duck Curve" (see Figure 1) is a depiction of this emerging change that has become commonly recognized throughout the electric sector. Figure 1 illustrates an hourly demand and net demand (net of solar and wind) analysis for a sample day, based on an example southern California utility that is expected to add 600 MW of distributed solar, 1250 MW of utility-scale solar, and 725 MW of wind capacity in response to the state Renewable Portfolio Standard (RPS) by the year 2020.[1]

Figure 1



1 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 and is not intended to represent a "normal" or "summer peak" day. It is selected to illustrate the opportunities available to meet a challenging situation.

The total load line in Figure 1 shows the utility's projected total load, by hour, during the day. The Load Net of Wind/Solar line shows the load that the utility will face after expected wind and solar generation serve a portion of the total load.

Figure 1 shows that the overall load has a moderate diurnal shape, but when 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 utilities. 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 raise questions about the long-term suitability of variable energy resources.

This paper identifies a number of low carbon strategies that can be applied to address 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.

Figure 2
Duck Sitting in Water

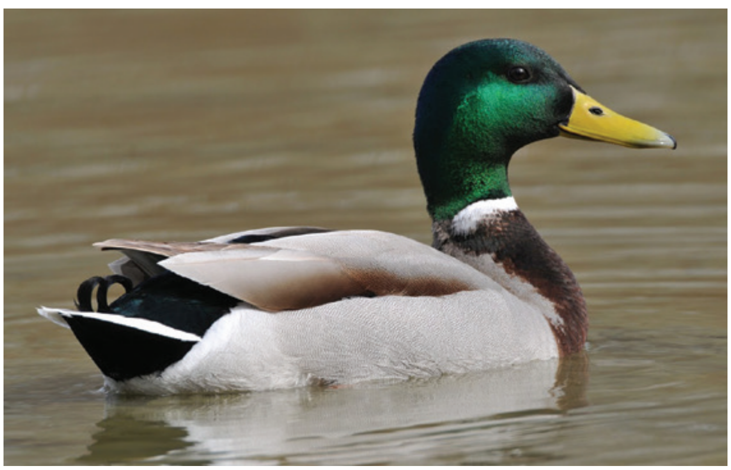


Figure 3
Duck in Flight

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 below, utility load shapes can do the same.

A duck in water tends to center its weight in the water, floating easily. Figure 2 shows the duck shape commonly associated with the graph in Figure 1.

A duck in flight, however, stretches out its profile in order to create lower wind resistance in flight. This is illustrated in Figure 3.

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 more output during the afternoon high load hours. Many of these strategies are already employed on a modest scale in the United States and European Union, while others are 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 4 shows the change in shape of the Duck Curve from the ten strategies we propose below. Like an actual duck, it becomes more streamlined and more able to "take flight."

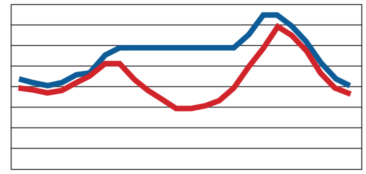
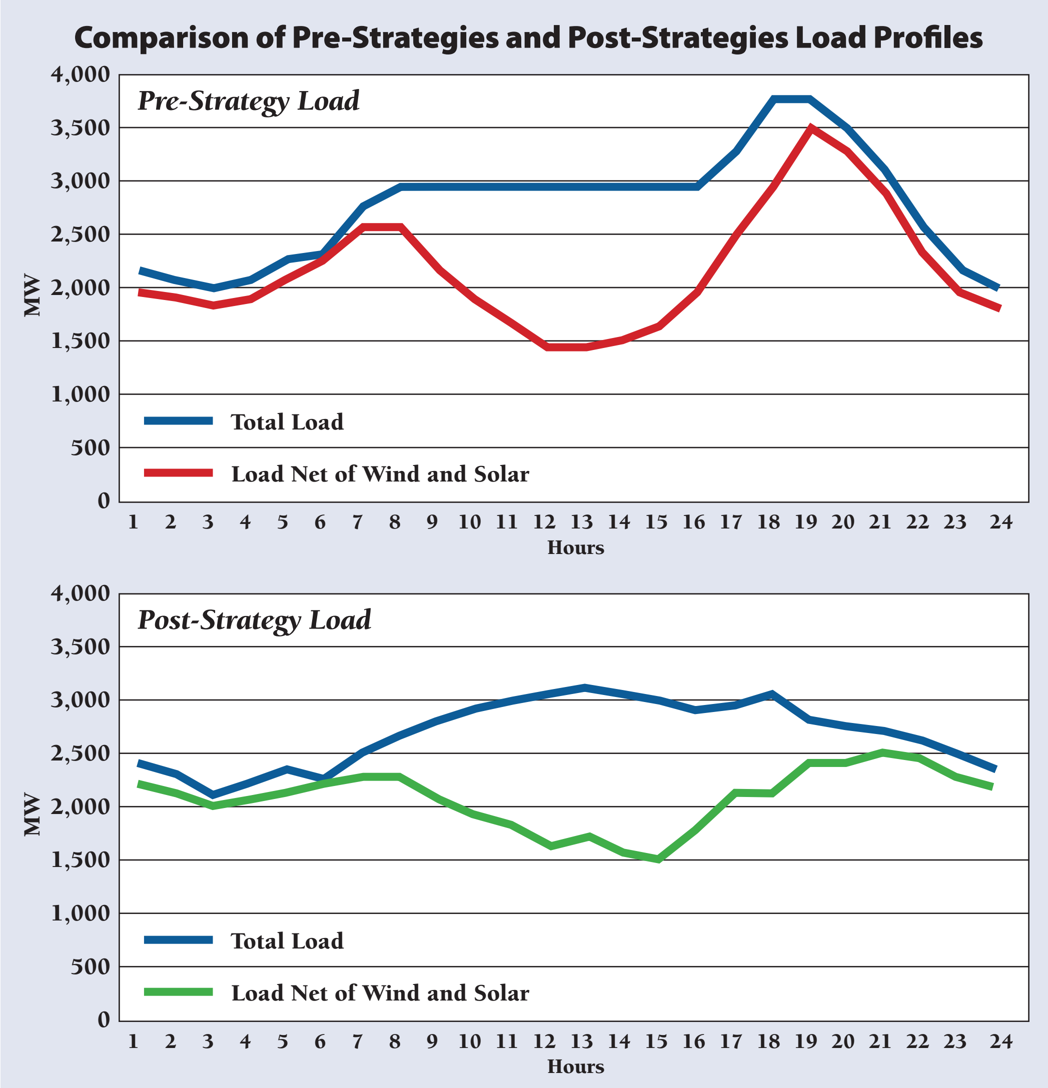


Figure 4



We include the following ten strategies:

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

Strategy 2: Orient fixed-axis solar panels to the west;

Strategy 3: Substitute solar thermal with a few hours storage in place of some projected solar PV generation;

Strategy 4: Implement service standards allowing the grid operator to manage electric water heating loads to shave peaks and optimize utilization of available resources;

Strategy 5: Require new large air conditioners to include two hours of thermal storage capacity under grid operator control;

Strategy 6: Retire inflexible generating plants with high off-peak must-run requirements;

Strategy 7: Concentrate utility demand charges into the "ramping hours" to enable price-induced changes in load;

Strategy 8: Deploy electrical energy storage in targeted locations, including electric vehicle charging controls;

Strategy 9: Implement aggressive demand-response programs; and

Strategy 10: Use inter-regional power transactions to take advantage of diversity in loads and resources.[2]

2 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, June 10). Meeting renewable energy targets in the west at least cost: the integration challenge. Western Governors' Association. Available at: http://www.westgov.org/component/docman/doc_download/1610-meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration-challenge-full-report?Itemid.

All of these strategies use existing technologies and can be implemented in a short period of time – in conjunction with a rapid rollout of renewable energy technologies – so that reliable and economical electricity service would not be put at risk. Each is described in general terms and depicted graphically to show how each contributes to reshaping loads and resources to enable grid operators to manage the renewable transition without fear of resource inadequacy, price spikes, curtailment of renewable energy, or other duck-related symptoms. After discussing each strategy individually, we show the incremental effect of that strategy, layered on those before it, to show the combined effects of the strategies. By the end of our discussion of Strategy 10, the reader sees the effect of implementing the combination of all of these strategies.

The pre-strategy load predicted for 2020 is a very challenging situation for utilities that have evolved without variable renewable energy on their systems. Comparing the pre-strategy load profile to the post-strategy profile, as shown in Figure 4, suggests that system operators will have more manageable ramping responsibilities if the strategies are implemented. The peaks have been shaved, the valleys filled, and the net load to be served with dispatchable resources has been smoothed. The duck can fly.

It is instructive to compare the task that system operators face with the load profile currently forecast without the addition of renewables to that which they would face with the addition of renewables and the implementation of the ten strategies identified in this paper. The combination of renewables and strategies is an easier system to manage than a system without the addition of renewables.

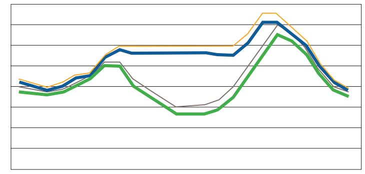
This shows that the combination of strategies actually more than offsets the system flexibility challenges created by addition of renewable resources, making it easier for the grid operator to dispatch available resources to ensure reliable and economical service. Or, put another way, these strategies solve the challenge created by the addition of renewable resources twice over, meaning that if only half of the assumed potential is achieved in practice, the utility will have no more difficulty maintaining reliable service than they would without the renewable resources and without the strategies.

Table 1

Comparison of Existing System Operation vs. System Operation with Renewables and Strategies

	Total Load Without Renewables or Strategies	Net Load With Renewables and Strategies
Load Factor	73.6%	83.3%
Maximum Hourly Ramp	500 MW	340 MW
Total Difference Between Highest and Lowest Hour	1800 MW	950 MW

Each of the graphs represented herein shows the cumulative effects of strategies on the total and net load. Pre-strategy total and net load show cumulative effects of previous strategies, and post-strategy total and net lines show incremental changes from the previous strategy.



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

The rapid increase in loads to be served from dispatchable resources that occurs 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 utilities.

A key element of demand during this period is residential lighting, and conveniently, 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 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.

Table 2 shows the expected improvement in LED lighting efficiency and reduction in LED lighting cost over this decade.

Table 2

LED Device Efficacy and Price Are Expected To Continue to Improve Rapidly[3]

Lamp Type	2010	2012	2015	2020
LED Cool White Efficacy (lumens/watt)	134	176	224	258
LED Cool White Price ($/1000 lumens)	$13.00	$6.00	$2.00	$1.00
LED Warm White Efficacy (lumens/watt)	96	141	202	253
LED Warm White Price ($/1000 lumens)	$18.00	$7.50	$2.20	$1.00

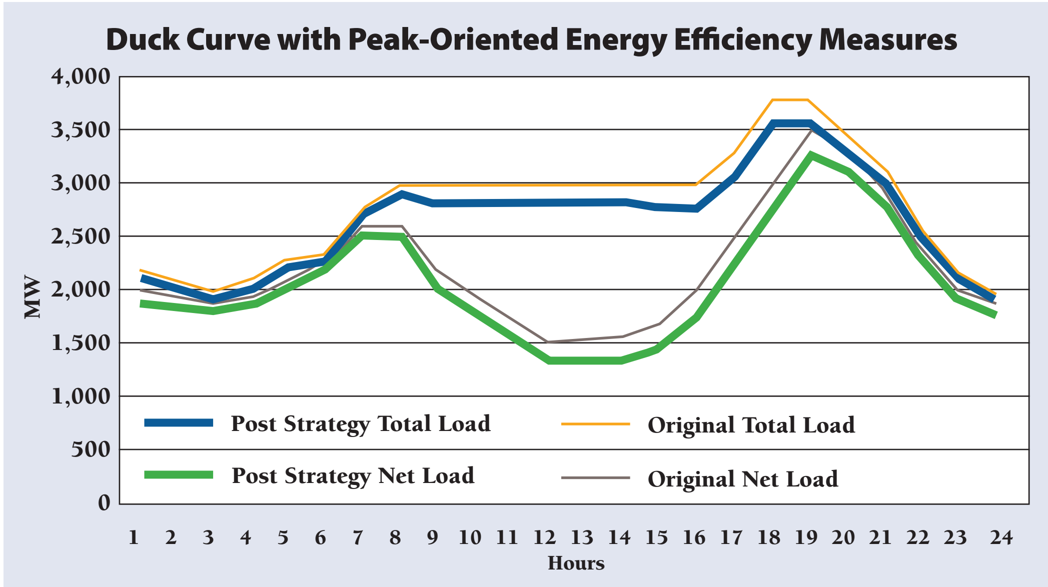
LED retrofits in the office environment could also provide significant cost-effective energy savings during the business day, but not necessarily continuing after 5 PM when many office lights are turned off. In the retail environment these savings will predictably extend into the early evening hours when the ramping challenge is most significant. Retrofit in the retail sector is therefore more valuable than the office sector for this strategy to achieve its goal, as savings during the day that do not continue into the evening hours will not reduce the ramping requirement.

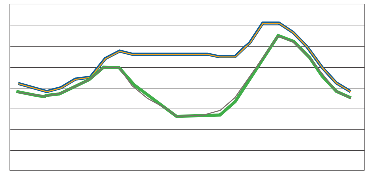
There are other afternoon and evening peak loads that are also amenable to efficiency measures, including air conditioning, televisions, and cooking appliances. Each of these must be examined to determine the level of savings achievable through implementation of appliance standards and retrofit incentive programs.

3 U.S. Department of Energy. (2013, April). Solid-State Lighting Research and Development: Multi Year Program Plan. Available at: http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/ssl_mypp2013_web.pdf.

Figure 5 shows the Duck Curve after implementation of energy efficiency measures totaling about five percent of total usage and targeted at peak hours (but providing some savings across all hours).

Figure 5





Strategy 2: **Orient solar panels to the west.**

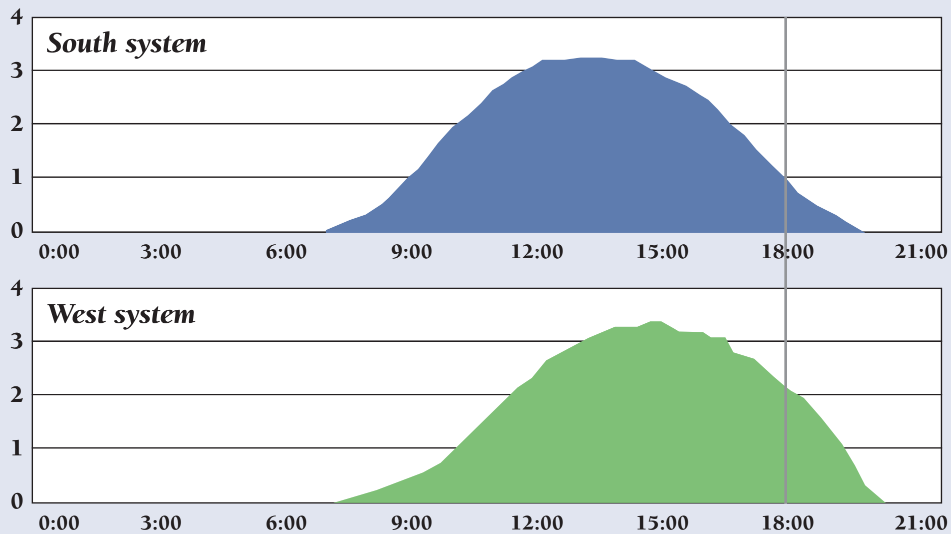
It is now generally accepted that orienting solar panels to the west-southwest increases the output during the afternoon hours, while reducing output during morning hours. This would produce a more valuable profile of power output, better suited to the shape of load to be served. Although utility-scale solar photovoltaic (PV) systems are often installed with "tracking" systems that follow the sun from east to west, distributed systems are most often installed on fixed racking that faces south to maximize the total kWh production. In this example, we take the amount of solar energy assumed in this illustration (a total of 1850 MW, of which 600 is assumed to be distributed solar), and assume that reorientation reduces output by 100 MW during the morning hours of 9 to 11 AM, and increases output by 100 MW between 3 PM and 5 PM, leaving the total solar output unchanged. However, as the graph below indicates, the utility now has additional solar output during the critical system peak timeframe.

Figure 6 shows how panel orientation affects solar output from hour to hour.

Figure 6

Hourly Solar PV Fixed-Rack System Output[4]

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

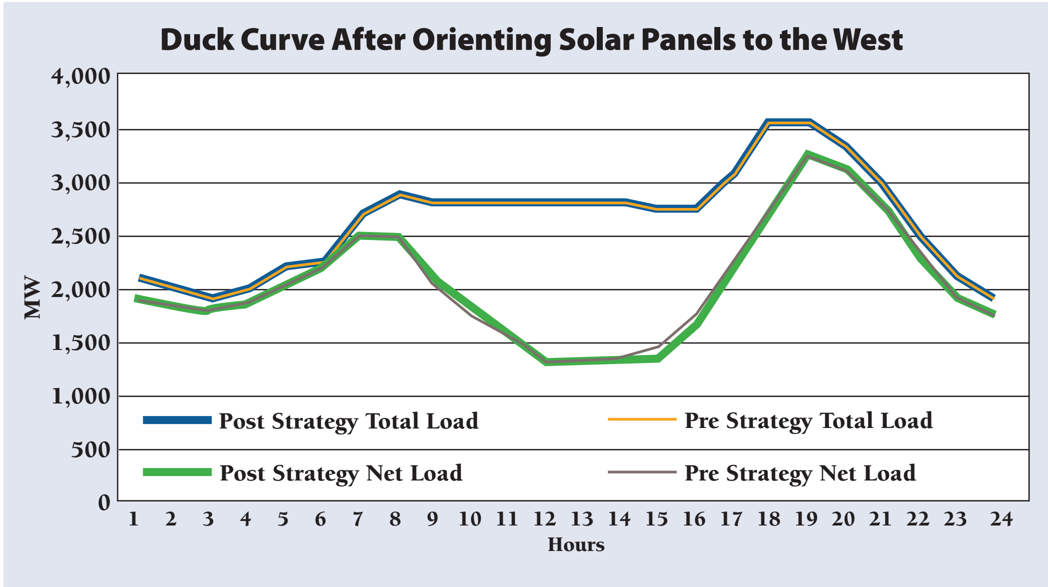


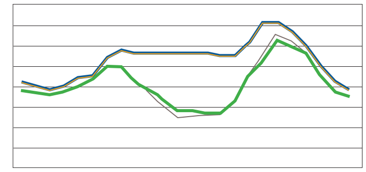
With time-varying rates, consumers will realize greater value from their PV investment by installing racking to orient the panels toward the west. Properly designed, this should compensate customers for any slight reduction of total PV output that results from this strategy – a significantly higher price per kWh for the same or slightly lower output.

4 Pecan Street Research Institute. (2013, November). South-facing solar cut peak demand from grid 54% – west-facing systems, 65%. Available at: http://www.pecanstreet.org/2013/11/report-residential-solar-systems-reduce-summer-peak-demand-by-over-50-in-texas-research-trial/

Figure 7 shows the total and net load for our illustrative utility after implementation of Strategies 1 and 2.

Figure 7





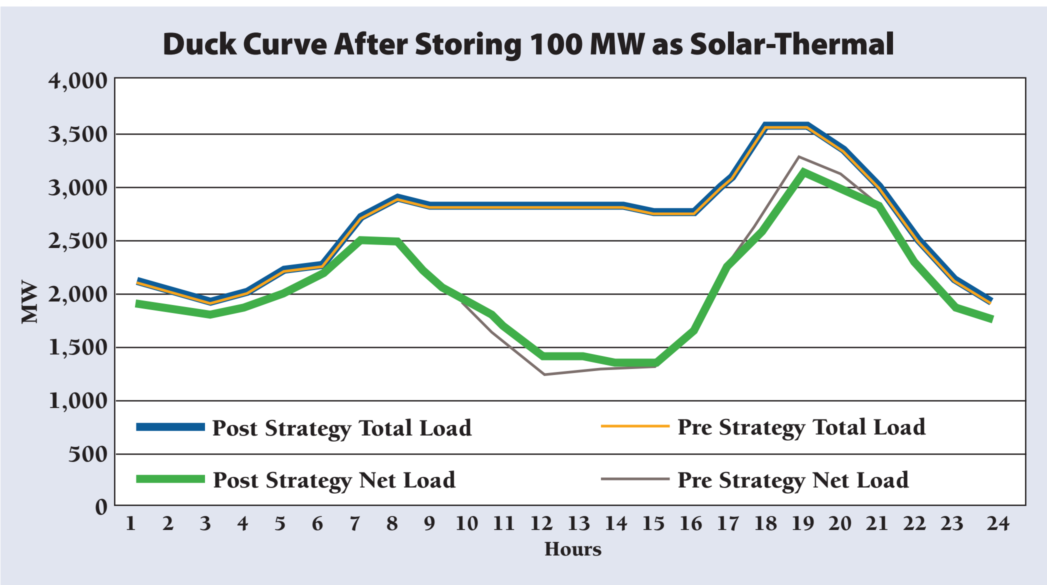
Strategy 3: Substitute solar thermal with a few hours of thermal storage in place of some projected solar PV generation.

The dominant solar technology embedded in the Duck Curve is PV generation. This technology is limited to producing electricity only at the time that the sun is shining. An alternative, albeit at a slightly higher cost, is solar thermal generation in which the solar energy is used to heat a fluid that can be stored for usage to generate electricity during later hours.

Our illustrative utility is projected to have 1250 MW of installed utility-scale solar capacity by 2020; only a fraction is in place today. This strategy implies changing this future mix to include 100 MW of solar thermal generation. Our depiction of this option takes just 100 MW of generation from three hours in the middle of the day, and stores it for use in the 6 PM to 9 PM period. While storage of more than a few hours is technically feasible, our purpose here is to illustrate this concept. This storage technology is being deployed in Arizona today, and is installed with six hours of storage, or twice as much as we assume here.[5]

Figure 8 shows the total load and net load to be served from dispatchable resources after implementation of Strategies 1–3.

Figure 8



5 Owano, Nancy (2013, October 11). Arizona solar plant achieves six hours after sun goes down. Phys.org. Available at: http://phys.org/news/2013-10-arizona-solar-hours-sun.html.

Strategy 4: Implement service standards allowing the grid operator to manage electric water heating loads to shave peaks and optimize utilization of available resources.

The United States has about 45 million electric water heaters in service. Residential hot water usage 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.

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.

One favored strategy involves "supercharging" water heaters to higher temperatures, and using a blending valve to deliver normal hot water temperatures. In this manner, the grid operator is using currently available but unused storage capacity within existing water heaters. This means that the consumer actually receives better water heating service than he or she would absent these supercharging and blending controls.

Electric water heating is dominant in the Pacific northwest and in the south, and natural gas water heating is dominant in California. But even the investor-owned utilities in California have approximately ten-percent electric water heat saturation, or about one million installed units, primarily in mobile homes and multifamily housing.[6] Using these water heaters to help balance the loads and resources of an urban utility will require new institutional arrangements, but the controls can easily be installed and managed in very short periods.

One million electric water heaters means that up to 4000 MW of load could be dispatched as needed, and that up to 10,000 MWh per day could be shifted as needed. For our illustrative utility, with about ten percent of this statewide total, full implementation of water heater controls on 100,000 electric water heaters would enable the utility to add about 450 MW at any single hour, and to shift a total of about 1000 MWh of energy between periods of the day. To be conservative, we use only one-third of this total (a maximum of 150 MW in any hour, and 300 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 is a conservative implementation compared with projects being advanced in Canada and Hawaii to use electric water heating controls to add system flexibility.[7]

6 KEMA. (2010, October). 2009 California Residential Appliance Saturation Study. Prepared for the California Energy Commission. Available at: http://www.energy.ca.gov/appliances/rass/.

7 Integral Analytics (2013, October 31). Renewable integration utilizing GIWH technology. Presented at the Peak Load Management Association. Available at: http://c.ymcdn.com/sites/www.peaklma.org/resource/resmgr/2013fallarchive/kallock_giwh.pdf.

Figure 9 shows the Duck Curve with Strategies 1–4 implemented.

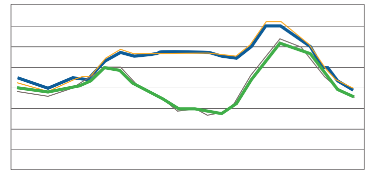
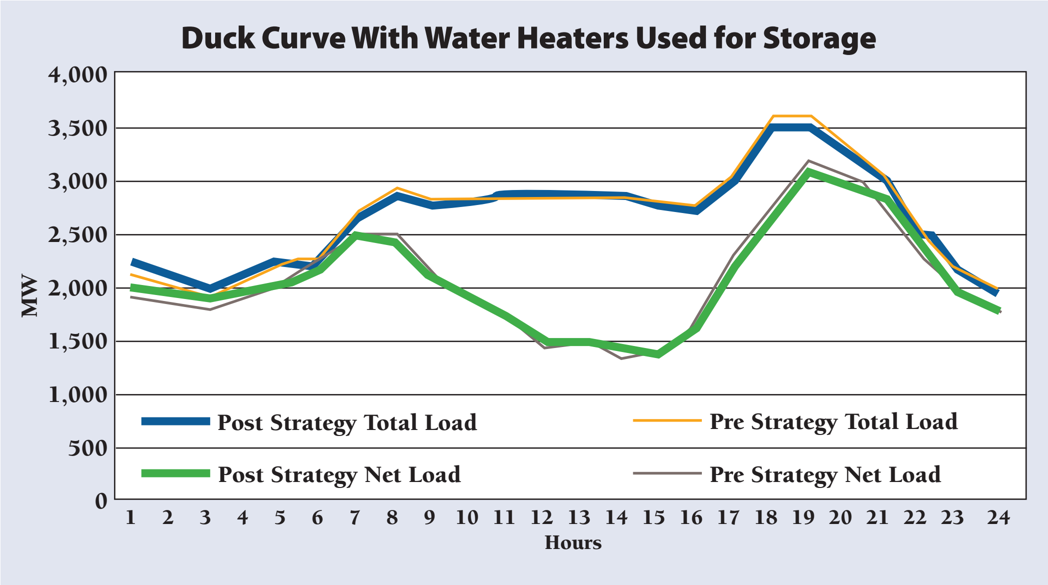


Figure 9



Strategy 5: Require new air conditioners to include two hours of thermal storage capacity under grid operator control.

A large part of the peak demand challenge in most of the United States is the amount of air conditioning load, both residential and commercial, that contributes to the afternoon and early evening peak demand. In summer, this is the dominant load, whereas in winter it is greatly diminished. For conservatism, we assume only very limited amounts of air conditioning load.

This strategy would require new central air conditioners and large-building cooling systems to include two hours of thermal storage, meaning that a five-ton unit (60,000 BTU/h) would have to have a minimum of 120,000 BTU of storage in the form of ice or chilled water. These types of devices are commercially available from Ice Energy and other manufacturers today.

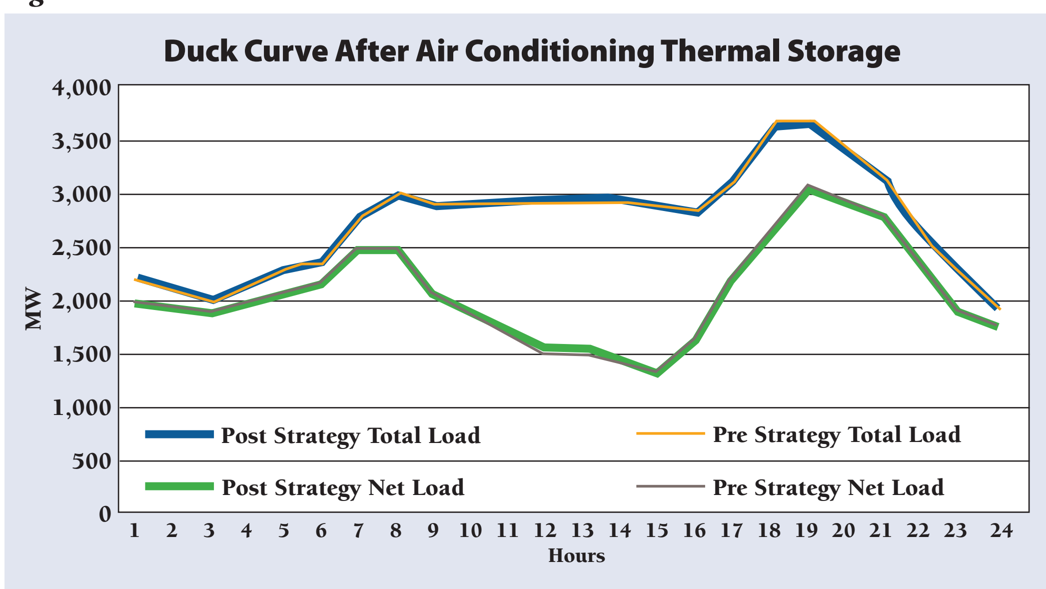
Figure 10
Ice Bear Storage Air Conditioners

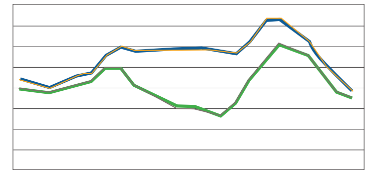
Figure 10 shows the Ice Bear storage commercial air conditioning unit. These devices actually provide both peak and energy savings, because they "make cold" at night, when temperatures are lower and the chilling units operate more efficiently, offsetting the usual "round-trip losses" associated with electrical energy storage.

For this strategy, we remove 50 MW of air conditioning load from the 6 PM to 8 PM period, and provide for this need by pre-chilling the storage fluid mid-day. The effect for the utility is a load that increases in the early afternoon when solar is prevalent, and decreases in the early evening when cooling is provided from storage. In summer months, this could be as much as ten times the load shift as in the shoulder season we use for illustration here.

Figure 11 shows the Duck Curve after implementation of Strategies 1–5.

Figure 11





Strategy 6: Retire inflexible generating plants with high off-peak must-run requirements.

Many utilities have 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.[8]

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. While these retirements do not alter the utility's total load or residual load — the load filled by wind and solar which 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 in order 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.

This strategy leaves more room on the system for replacement units, generally natural gas fueled, which 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 due to 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 install more flexible replacement capacity.

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 high-efficiency natural gas generation fleet, we have met our challenge.

8 U.S. Energy Information Administration. (2012, July 31). Projected retirements of coal-fired power plants. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=7330.

Strategy 7: Concentrate utility demand charges into the "ramping hours" to enable price-induced changes in load.

Electric utilities employ tariffs for commercial and industrial consumers that contain demand charges. 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 with uneven usage a higher average price. Today, with variable wind and solar generation creating bulges in the availability of low-cost energy supply, it makes more sense 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: 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 time-of-use (TOU) energy charge during the hours when the system is expected to face stress.[9]

Here we assume that by targeting the demand charges to a maximum of six hours per day, and applying that charge hourly during those periods (i.e., one-sixth of the demand charge collected based on the customer's load in each of the six hours), it will be possible to reduce loads during those hours, with corresponding price decreases and load increases in other hours. Some analysts report that TOU pricing will produce net reductions in total usage, but because we treat demand response as a separate strategy, we assume that lower use during high-cost hours under a TOU rate is offset by an equal amount of higher use in lower-cost hours.

For example, with this type of rate design, office buildings may choose to schedule building janitorial service during early morning hours or 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.

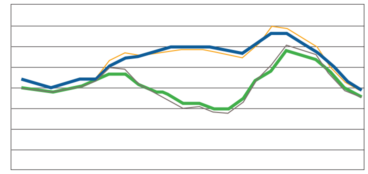
For this to be effective, it is crucial that utilities not have demand ratchets that would require payment of a demand charge based on usage in a different period than the targeted hours. A demand ratchet charges customers throughout the year based on their highest monthly usage, and thus weakens the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

Southern California Edison is an example of a utility with a peak-concentrated demand charge, that has been in place for over a decade for large commercial customers. The on-peak demand charge is applied only six hours per day, five days per week, for the four summer months.

Although some form of advanced metering is needed to measure and bill a time-varying demand charge, these meters need to be installed 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.[10]

9 We address demand-response programs directed at a small number of hours per year separately.

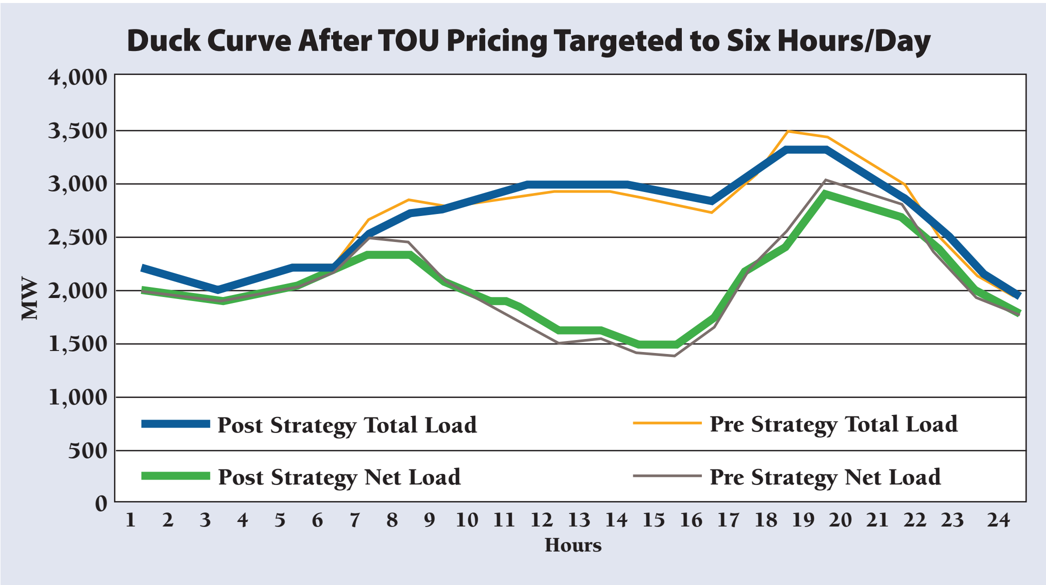
10 See: Lazar, J. (2012). Rate design where advanced metering infrastructure has not been fully deployed. The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6516.



Our assumption is that targeted pricing can reduce load by five percent during those hours with the largest gap between total load and the output of wind and solar generators, with the reduced load made up 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.[11]

Figure 12 shows the Duck Curve after implementation of Strategies 1–7.

Figure 12



11 See: Faruqui, A., Hledik, R., and Palmer, J. (2011, July). Time-varying and dynamic pricing. The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/5131.

Strategy 8: Deploy electrical energy storage in targeted locations.

Electrical energy storage is very expensive, but it 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 energy storage addressed in Strategy 3 (solar thermal), 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 re-converted to electricity.

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 and require additional transmission investment to bring that capacity to the service territory. Other large-scale technologies 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 and a place to "park" surplus generation due to 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 should be compared to installing batteries at distributed points where they may displace expensive grid upgrades.

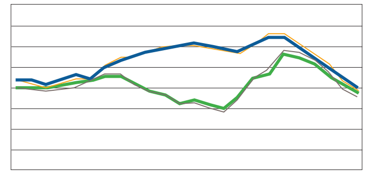
This strategy includes both installation of new battery banks or compressed air storage units, as well as the use of existing batteries, such as those in electric vehicles and uninterruptible power supplies. The strategy is to selectively charge storage batteries when power is available and to use the battery resources when power is scarce.

The simple application of this 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 (V2G) – are being tested and may become available within this decade. These V2G 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/environmental benefits they provide, not just to the deferred distribution capacity upgrades.

For purposes of this paper, we assume that the illustrative utility 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.[12] 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

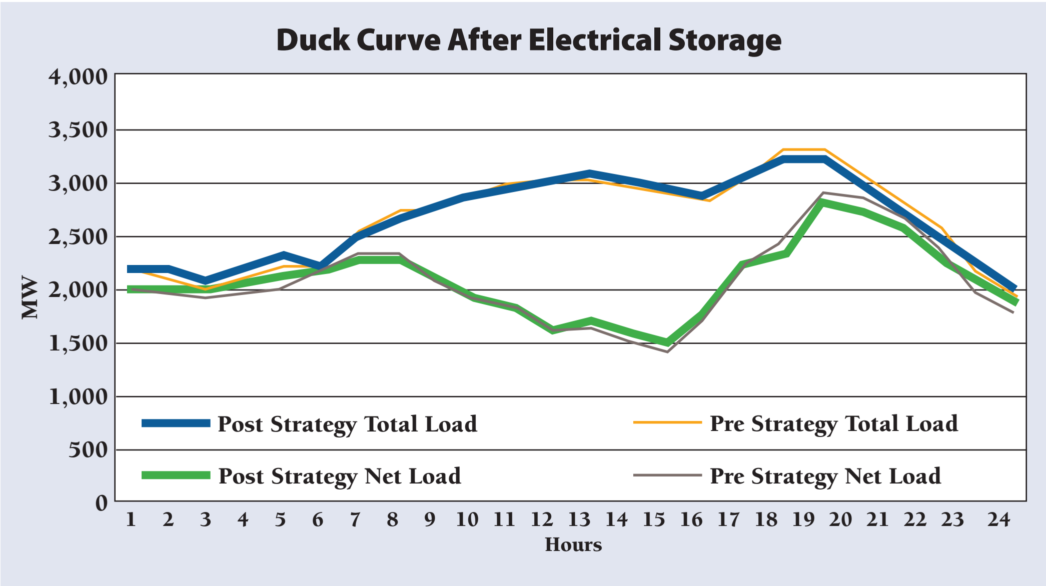
12 In October 2013, the California Public Utilities Commission directed regulated utilities to acquire 1325 MW of storage capacity by 2020 in Rulemaking 10-12-007; Strategy 8 is slightly less aggressive than the California requirement.



peak hours than is used to produce 620 MWh during periods of surplus energy.

Figure 13 shows the Duck Curve after implementation of Strategies 1–8.

Figure 13



Strategy 9: Implement aggressive demand-response programs.

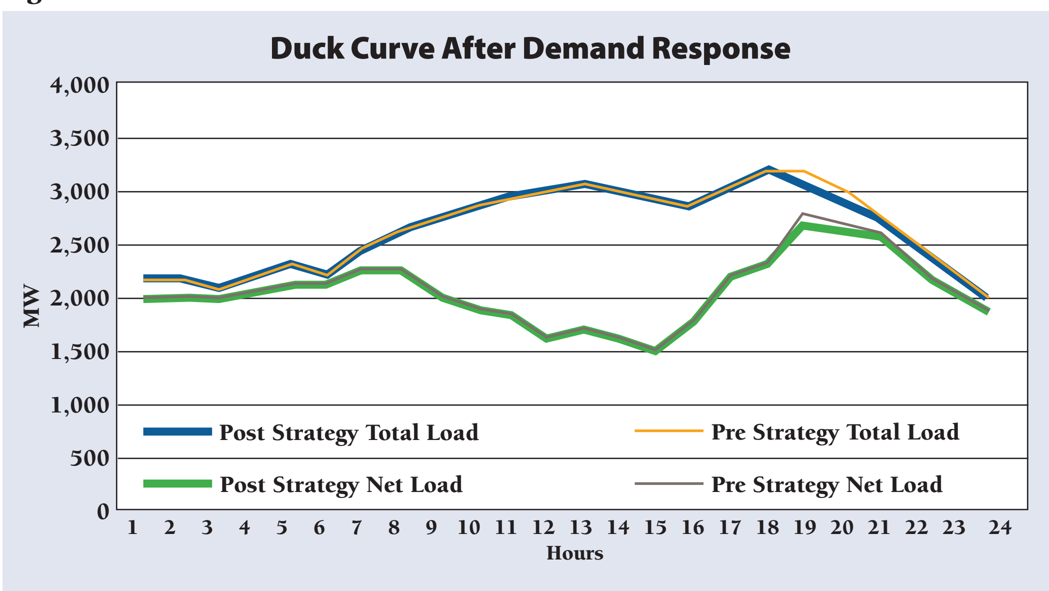
Many of the strategies listed previously have the characteristic of what is known as "demand response" – programs to entice consumers to change their load patterns. Experience with the New England Independent System Operator (ISO-NE) in particular has shown that the creativity of private sector aggregators can attract significant demand response during peak load periods. ISO-NE has over 2100 MW of demand-response commitments in place (out of a total of about 25,000 MW of peak demand, or about eight percent of peak demand).[13]

Because we have included significant peak load shifting in response to water heater management (Strategy 4), air conditioner thermal storage (Strategy 5), and concentration of utility demand charges into the key hours of the day (Strategy 7), we have used a significant portion of available demand response.

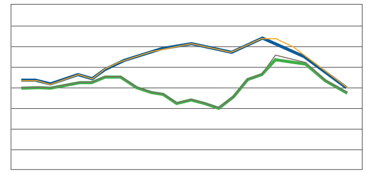
The experience in New England shows that demand response of about eight percent of peak demand is possible and cost-effective. Given the measures we have already counted, such as time-focused demand charges, storage air conditioning, and storage water heating, we assume that three percent peak demand attenuation (about 100 MW for our illustrative utility) through demand-response programs for the three 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 three percent is economic curtailment – a cut in peak demand without any associated growth in other hours.

Figure 14 shows the Duck Curve after implementation of Strategies 1–9.

Figure 14



13 ISO-New England. (2014, January). Demand resource assets enrollment. Available at: http://iso-ne.com/genrtion_resrcs/dr/stats/enroll_sum/index.html.



Strategy 10: Use inter-regional power exchanges to take advantage of diversity in loads and resources.

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.

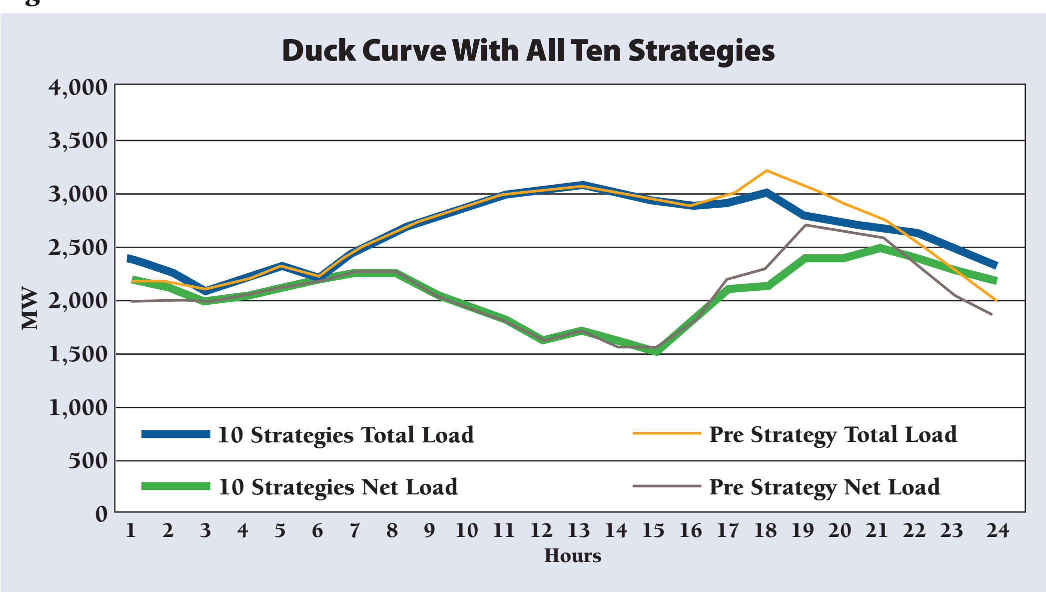
For decades, power has flowed from the northwest to California during the spring runoff, and transmission lines were constructed to facilitate these low-cost energy purchases. Use of transmission lines originally designed for off-peak usage to also enable on-peak power exchanges has increased in the past decade, with many utilities engaged in peak capacity swaps. With over 8000 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 hours 17–21 to hours 22–03. 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 15 shows the Duck Curve with all ten strategies implemented.

Figure 15



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. Figure 16 shows the end result compared with the starting point.

Figure 16

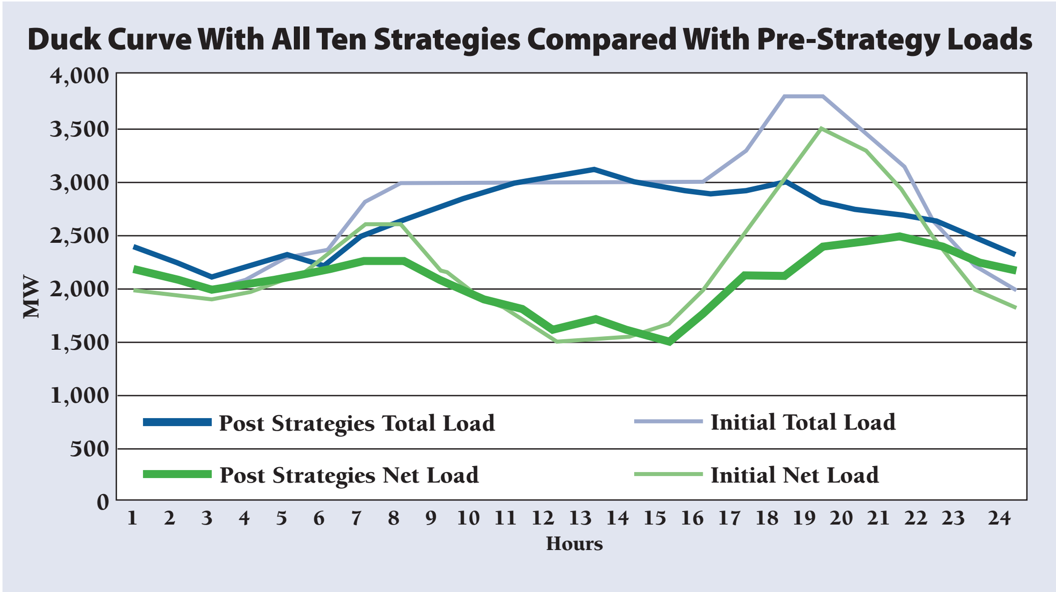
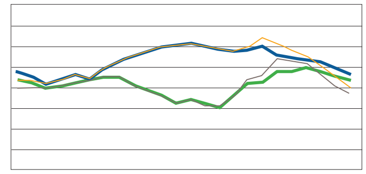


Figure 17
Airborne Ducks

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

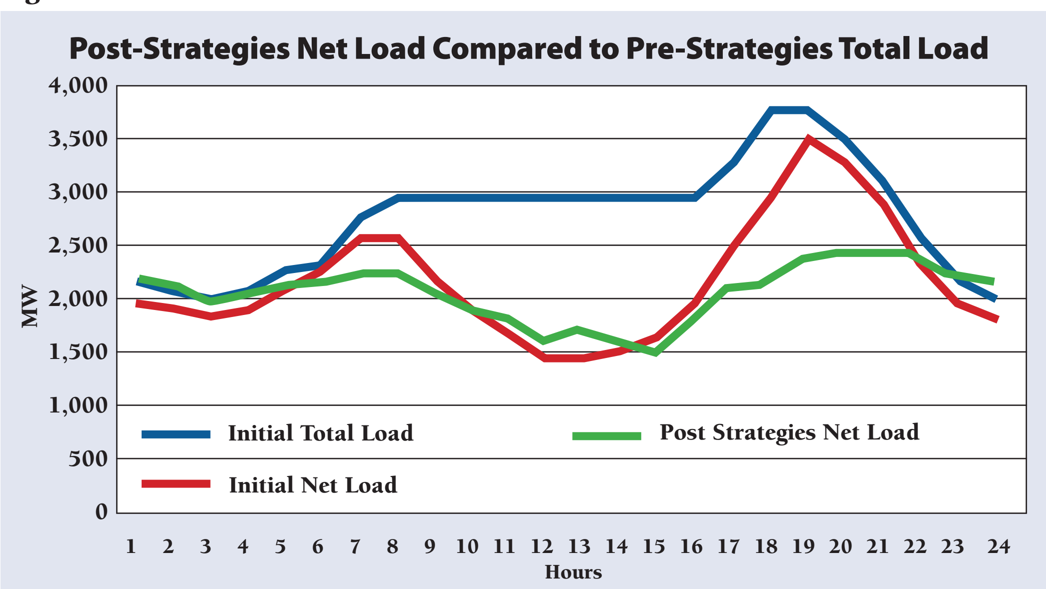


How the Duck Curve With All Ten Strategies Compares to Pre-RPS Conditions

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 can be selected over time to meet the needs of the future. It is not necessary to completely flatten load to eliminate the ramping challenge of today's renewable energy transition. Ramping requirements only need to be brought within the capability of evolving utility grids. Figure 18 and Table 3 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 beyond that which would exist without the renewable resources, and also that the hour-to-hour ramping requirements are smaller than would otherwise exist.

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. This is desirable for almost any electric utility system, including those without significant renewable energy deployment issues.

Figure 18



It's 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 portion of the load to schedule when it can most economically charge water heaters, air conditioners, and batteries. In essence, the effect of the ten strategies is to reduce both peaking needs and ramping requirements. The statistics in Table 3 illustrate this.

Table 3

Load Factor and Maximum Hourly Ramping Requirements

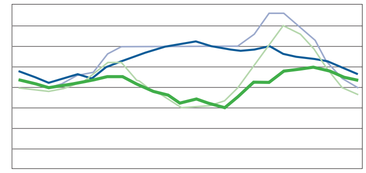
	Total Load Without Renewables or Strategies	Net Load With Renewables and Without Strategies	Net Load With Renewables and With Strategies
Load Factor	73.6%	63.6%	83.3%
Maximum Hourly Ramp	500 MW	550	350 MW
Total Difference Between Highest and Lowest Hour	1800 MW	2000 MW	950 MW

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 one-half of the energy shifting and shaping incorporated in these ten strategies would result in the load following with renewables in 2020 no more challenging than load following without renewables.

We conclude that adequate tools 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.

Related RAP Publications



Clean Energy Standards: State and Federal Policy Options and Implications
http://www.raponline.org/document/download/id/4714

This report introduces the concept of a Clean Energy Standard (CES), a type of electricity portfolio standard that sets aggregate targets for the level of clean energy that electric utilities would need to sell while giving electric utilities flexibility by: (1) defining clean energy more broadly than just renewables, and (2) allowing for market-based credit trading to facilitate lower-cost compliance. The report explains how a CES works, describes the benefits that a CES can deliver, and explores federal and subnational options for CES policies. It also explores the nuances of CES policy design and the implications of different design choices.

Electricity Regulation in the US: A Guide
http://www.raponline.org/document/download/id/645

The purpose of this guide is to provide a broad perspective on the universe of utility regulation. The paper first addresses why utilities are regulated, then provides an overview of the actors, procedures, and issues involved in regulation of the electricity and gas sectors. The guide assumes that the reader has no background in the regulatory arena, and serves as a primer for new entrants. It also provides a birds-eye view of the regulatory landscape, including current developments, and can therefore serve as a review tool and point of reference for those who are more experienced.

Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues
http://www.raponline.org/document/download/id/4572

States have jurisdiction over most interconnections of distributed generation to utility systems in the U.S. While a majority of states have established interconnection regulations, they tend to focus on the smallest systems. This paper provides recommendations for state interconnection rules for distributed generation in the 10- to 20-megawatt range. It covers technical requirements, procedures and agreements to preserve the safety, reliability, and service quality of electric power systems and make interconnection as predictable, timely, and reasonably priced as possible. Emerging interconnection issues that states will need to address in the future also are covered, including high penetration of distributed generation, advances in technology, and screening criteria that set interconnection study requirements.

Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge
http://www.raponline.org/document/download/id/5041

This paper explores approaches for reducing costs to integrate wind and solar in the Western US, 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. The paper provides an overview of these approaches; assesses costs, integration benefits, and level of certainty of these appraisals; and provides estimated timeframes to put these measures in place.

Power Markets: Aligning Power Markets to Deliver Value
http://www.raponline.org/document/download/id/6932

Wholesale markets will play a key role in driving investment in the flexible resources needed to ensure reliability as the share of intermittent renewable resources grows. In Power Markets: Aligning Power Markets to Deliver Value <http://americaspowerplan.com/the-plan/power-markets/> , Mr. Hogan identifies three areas where power markets can adapt to enable an affordable, reliable transition to a power system with a large share of renewable energy. These are a) recognize the value of energy efficiency, b) upgrade grid operations to unlock flexibility in the short-term, and c) upgrade investment incentives to unlock flexibility in the long-term.

Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know
http://www.raponline.org/document/download/id/4909

This report is addressed to state regulatory utility commissioners who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. The report provides regulators with a thorough discussion of risk, and suggests an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand, and minimize the risks associated with electric utility resource investment. This approach is expected to result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed
http://www.raponline.org/document/download/id/6516>

This paper identifies sound practices in rate design using conventional metering technology. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates to reflect 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.

Recognizing the Full Value of Energy Efficiency
http://www.raponline.org/document/download/id/6739

Energy efficiency provides numerous benefits to utilities, to participants (including rate payers), and to society as a whole. However, many of these benefits are 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. This report is meant to provide a comprehensive guide to consideration and valuation (where possible) of energy efficiency benefits.

Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar
http://www.raponline.org/document/download/id/6891

Increased adoption of distributed solar photovoltaics (PV), and other forms of distributed generation, have the potential to affect utility-customer interactions, system costs recovery, and utility revenue streams. If a greater number of electricity customers choose to self-generate, demand for system power will decrease and utility fixed costs will have to be recovered over fewer kilowatt hours of sales. As such, regulators will need to determine the value and cost of additional distributed PV and determine the appropriate allocation of the costs and benefits among consumers. The potential for new business models to emerge also has implications for regulation and rate structures that ensure equitable solutions for all electricity grid users. This report examines regulatory tools and rate designs for addressing emerging issues with the expanded adoption of distributed PV and evaluates the potential effectiveness and viability of these options going forward. It offers the groundwork needed in order for regulators to explore mechanisms and ensure that utilities can collect sufficient revenues to provide reliable electric service, cover fixed costs, and balance cost equity among ratepayers—while creating a value proposition for customers to adopt distributed PV.

Revenue Regulation and Decoupling: A Guide to Theory and Application
http://www.raponline.org/document/download/id/861

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as decoupling and the policy issues associated with its use. We identify the underlying concepts and the implications of different rate design choices. This guide also includes a detailed case study that demonstrates the impacts of decoupling using different pricing structures (rate designs) and usage patterns.

Time-Varying and Dynamic Rate Design
http://www.raponline.org/document/download/id/5131

Time-varying and dynamic rates have the potential to avoid or defer resource costs, reduce wholesale market prices, improve fairness in retail pricing, reduce customer bills, facilitate the deployment of both distributed resources and end-use technologies, and reduce emissions. This report identifies rate design principles and the risk-reward tradeoffs for customers that must be considered in the design and deployment of time-varying rates. The report also summarizes international experience with time-varying rate offerings.

Designing Distributed Generation Tariffs Well
http://raponline.org/document/download/id/6898

Improvements in distributed generation economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in distributed generation adoption in the United States. Regulators are looking for the well-designed tariff that compensates distributed generation adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive. This paper offers regulatory options for dealing with distributed generation. The authors outline current tariffs and ponder what regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole. The paper highlights the importance of deciding upon a valuation methodology so that the presence or absence of cross-subsidies can be determined. Finally, the paper offers rate design and ratemaking options for regulators to consider, and includes recommendations for fairly implementing tariffs and ratemaking treatments to promote the public interest and ensure fair compensation.

Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements
http://www.raponline.org/document/download/id/4537

Energy efficiency measures provide valuable peak capacity benefits in the form of marginal reductions to line losses that are often overlooked in the program design and measure screening. On-peak energy efficiency can produce twice as much ratepayer value as the average value of the energy savings alone, and geographically or seasonally targeted measures can further increase value.

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