A Solved Problem

Existing measures provide low-cost wind and solar integration

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CONTENTS

1. EXECUTIVE SUMMARY

Electric system operators already manage a rapidly growing fleet of variable renewable energy generators, and are preparing to integrate even more. As penetration of wind and solar continues to grow, system operators will face challenges posed by increased levels of variable resources. However, they can easily address these challenges with the planning and operational tools already at their disposal, and at a low cost.

Variable resources experience rapid swings in generation caused by both expected solar declines at the end of the day and unexpected swings due to forecast errors. If conventional fuels and other resources were more flexible in two key ways (minimum loads and ramping needs), they could better support wind and solar technologies:

- Minimum loads are a result of mechanical and thermal constraints on conventional, steam-driven power plants, which cannot safely operate below 40-60 percent of their rated capacity. This limits the amount of renewable energy that can be brought online at a given time. Recent performance improvements have reduced the minimum load for new natural gas plants but older, inflexible units pose a cost on the system.

- Flexible plants can increase and decrease their level of power production rapidly—this change in production is referred to as “ramp.” The faster a flexible plant can increase or decrease its operating level, the more helpful it is in maintaining system balance. Ramp need not only be served by gas plants: storage, imports, and other flexible generation can also provide ramping needs.

In addition to reducing quantities of inflexible thermal generation, solutions that will help meet the incremental needs of the system as more renewable energy is brought online include:

- Improved coordination between neighboring system operators. Regional operators across the country are already improving coordination. Interregional integration can be improved even further with continued effort and without the need for incremental investments in new technologies or infrastructure.

- Increased geographic diversity of installation sites. Dispersion can reduce the incidence of rapid power swings.

- New transmission. Moderate, focused investments will allow the system to incorporate significant quantities of new energy.

- Demand-side solutions. Demand response is becoming better automated than it was in the past, and can provide rapid response to major events. Updated rate structures can also encourage customers to use energy in patterns that are easier for system operators to incorporate. Battery, pumped hydro, and compressed air storage all offer the potential to store energy from conventional sources during hours with low prices (often during times of significant renewable generation) to be used as needed later.

These measures do pose an incremental cost on the system, though most studies indicate this cost is relatively small, on the order of $5 per megawatt-hour (MWh) of energy for either wind or solar. Despite differences in the types of systems across the country, some composed of much more inflexible coal or nuclear generation than others, costs appear to follow similar bands for most systems. When totaling up integration costs, these studies typically include some combination of the cost of new flexible capacity, transmission investments, and/or additional balancing reserve requirements.

Measures to incorporate renewables are already underway, well understood, and should be planned for in the existing context of long-term system planning.

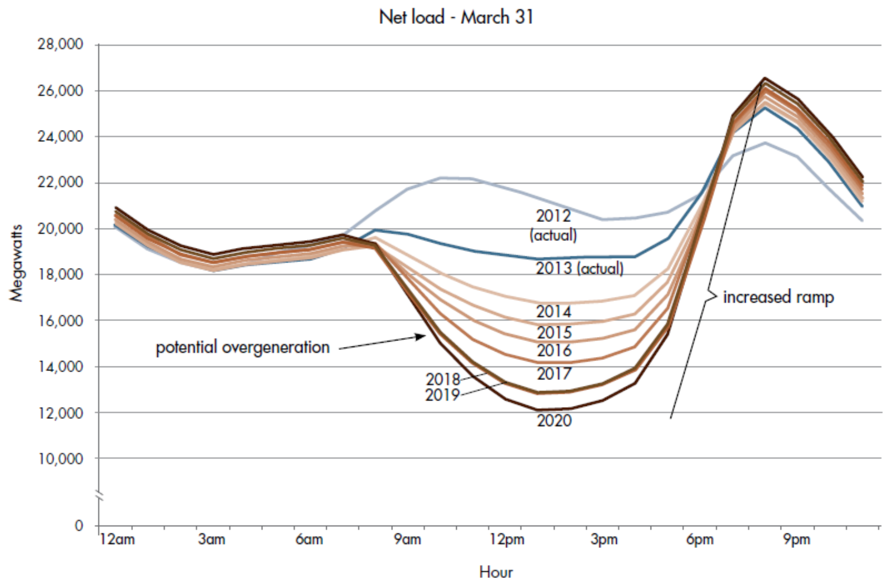
2. How is Renewable Energy Different?

Wind and solar energy are not generally dispatchable by system operators in the same sense as conventional fossil-fired generators. One critique commonly used to argue against the expansion of wind and solar energy is that this characteristic will cause the grid to become unreliable and unstable. Some argue that any additions of wind and solar must be balanced by some incremental conventional capacity that is dispatchable to the system operator. However, power systems are regional or multi-regional structures composed in part of many different forms of supply-side resources (e.g., conventional fossil fuels, hydroelectric, nuclear, solar, wind). Each and every one of these types of resource is sometimes unavailable to produce energy, for either planned or unplanned reasons. A well-interconnected power system can manage hourly fluctuations in variable resource output by ramping up the broad body of existing resources at a manageable rate. New gas combined-cycle plants can start quite rapidly, but are not necessary to balance variable resources in all circumstances.

2.1. Wind and solar output fluctuates throughout the day

Electric system operators are tasked with continually ensuring that supply and demand precisely match. Increasing levels of onshore wind and solar photovoltaics (PV) can create substantial ramping needs in the shoulder hours (the hours that precede and follow peak usage) when PV or wind output can change relatively rapidly. Some conventional power plants may generate little electricity during the day while solar generation is at its maximum, and need to ramp up quickly as the sun sets. This ramping pattern is represented in the California ISO’s “duck chart,” so called because the shape of the load curves resembles a duck (the chart is reproduced in Figure 1 below). The system in this chart is projected to need 12,000 MW of capacity to come online as solar output drops between 5 PM and 7 PM on March 31.

Figure 1: California "duck curve"



Source: California ISO. December 2013. "Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources." Available at: http://www.caiso.com/Documents/DR-EERoadmap.pdf.

Older coal units are particularly poorly suited to the task of ramping up quickly, but as retired coal units are replaced by more efficient and flexible gas units, the system will gain flexibility, and therefore an increased ability to integrate intermittent generators. Three factors increase the ability to respond to "duck curve" issues, or could even limit its occurrence:

- **System size:** Large, well-interconnected systems can take advantage of geographically diverse resources and loads, as well as more generators, to balance ramps using traditional methods. A large number of plants operating at half of their maximum load would be able to respond jointly to these fluctuations quicker than starting up plants that were offline in the middle of the day.
- **Demand response and smart grid:** New tools to actively reduce load in the early-evening peak hours, as solar generation is falling, can reduce the level of fossil ramping required, particularly by being available to shave (i.e., reduce) what would otherwise be the highest net peak load hours of the day.[1] The most extreme ramping events happen on only a few days per year, and the ability of system operators to call on customers to reduce loads, or shift consumption to another time of day, can reduce the need to purchase new gas capacity.
- **Changes in counting the capacity available:** Energy and capacity markets are already changing to value the ability of plants to ramp. Old, inflexible units put a cost on the system due to their poor performance in this regard. New markets may further

[1] "Net peak" is defined as the total demand at peak minus the level of intermittent generation.

incentivize flexible units, and replacements for retiring capacity are almost always more flexible.

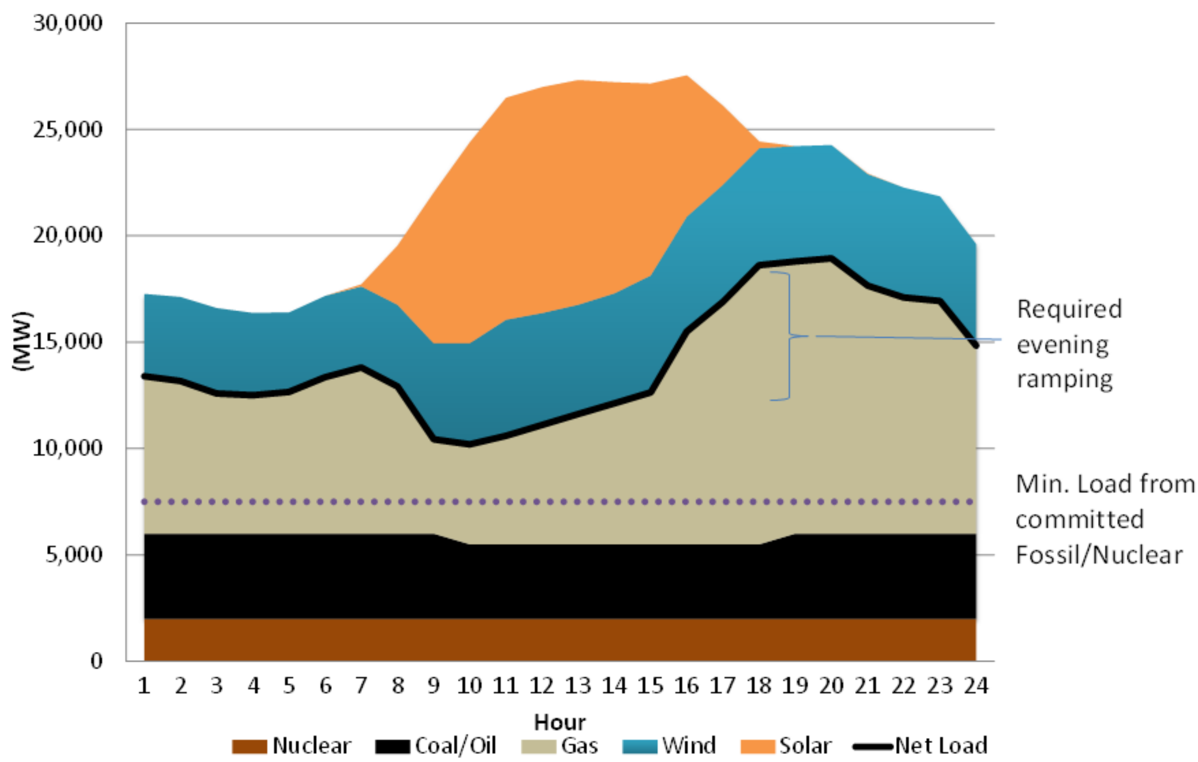
2.2. Minimum plant loading levels create costly operational challenges

The inflexibility of gas, coal, and nuclear plants could significantly constrain the power system in low load hours. Once units are "committed" in the previous day's day-ahead planning to be available for generation that day, they are turned on to serve load in a given hour. But these plants have a minimum power output level. For some older steam plants, this could be as high as 60 percent of the plant's rated capacity, though newer advanced plants could be much lower, down to 20 percent.[2] Once the plant is committed, the system must take this energy or force the plant to go entirely offline. This can pose a challenge on low load days in the spring and fall. The ability for wind and solar to serve load is represented by the difference between the total load and the aggregate of all the committed fossil minimum loads. This represents cost posed to the system by these committed steam plants.

Figure 2 shows a representative system dispatch with a substantial fraction of wind and solar. In this system, variable renewable energy serves 60 percent of the daily energy demands. The dotted line represents the minimum load from fossil plants that are committed and can't back down further. If the renewable energy was added to the point where it encroaches on this line, the system operator would have to take actions to get rid of the excess energy somehow. On an hourly operations basis, this could include exporting energy, curtailing renewable energy, or calling on new load sources. On a planning basis, the system could incentivize more flexible capacity with lower minimum loads through new market structures, increased demand response, and/or carefully designed contracts to export surplus power during key hours. These constraints are solvable by improved power plant design, but also by better integration and cooperation across the grid.

[2] Moelling, D., P. Jackson, and J. Malloy. March 1, 2015. "Protecting Steam Cycle Components During Load Operation of Combined Cycle Gas Turbine Plants." *POWER Magazine*. Available at: http://www.powermag.com/protecting-steam-cycle-components-during-low-load-operation-of-combined-cycle-gas-turbine-plants.

Figure 2: Representative hourly system dispatch



2.3. Variable resources can provide important reliability benefits

Concerns that increasing levels of renewable energy make the grid more vulnerable to outages and extreme events are overblown. The large quantity of physically spinning fossil generation assets are able to automatically respond to disturbances in a way that wind and solar resources are not, but technology developers have been actively working on this issue for a number of years. A study released in the spring of 2015 by General Electric and the National Renewable Energy Laboratory found that even with an 80-90 percent decrease in the amount of operational coal plants, the grid could respond to faults in a timely and reliable manner, with only modest transmission reinforcements.[3] The study found that a new system devoid of much conventional coal capacity could adequately address both transient stability (the ability of the grid to transition from normal operating conditions, through an outage, back to normal operating conditions) and frequency stability (the ability of the system to respond to a drop in frequency).

The benefits of conventional generators that are based on inertia could also be supplied by variable renewable resources. Wind turbine manufacturers have already developed control systems to allow turbines to provide "synthetic inertia" to the grid, allowing the turbine to generate a boost of power by

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[3] Miller, N., M. Shao, S. Pajic, and R. D'Aquila. 2015. "Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability." Available at: http://www.nrel.gov/docs/fy15osti/62906-ES.pdf.

slowing down if necessary. Solar systems could also implement such capabilities if added to smart inverters.[4]

Variable renewable technologies provide a benefit over conventional power plants in this regard as well. Most failures only bring down a small fraction of the overall plant—one wind turbine, or one array of panels—whereas a failure at a steam turbine risks a much larger outage. Such a small outage is much simpler for any power to system to automatically adjust and compensate for.

3. Facilitating Renewables Integration

Some have put forth that wind or solar energy must be balanced by gas generation at every hour to create a flat, firm power profile, to compensate for the uncertainty in wind forecasts. For example, ICF International conducted a study of firming requirements in Wyoming and found 516 MW of gas capacity were needed for every 2,000 MW of wind added, then used this to calculate incremental natural gas pipeline requirements in a later study for the Interstate Natural Gas Association of America.[5,6] This capacity would have to be dedicated to "firming" wind resources, and thus could not be used for other operations. While some additional reserves are likely necessary to compensate for forecast error uncertainty, studies such as ICF's ignore a number of the alternative solutions discussed in this report, including improved coordination among balancing authorities. Most importantly, the simplest cost-effective strategy to providing such reserves would be to utilize existing capacity where available, rather than a blanket assumption that new capacity is required.

Other analysis has shown that reserve requirements can vary substantially depending on the characteristics of the system. What is more concerning is that reserve requirements are calculated using numerous different statistical methods, which can have a large impact on the results.[7]

In this section, we describe several near-term solutions to variable resource integration that are far less expensive than matching new renewable capacity with new natural gas capacity. These include increased cooperation between system operators, geographic diversity of renewable resources, focused transmission investments, and demand-side measures.

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[4] NERC IVGTF Task 2.4 Report: Operating Practices, Procedures, and Tools. March 2011. Available at: http://www.nerc.com/files/ivgtf2-4.pdf.

[5] ICF International. December 2010. "Wyoming Wind Collector and Integration Study: Phase 2." Available at: http://www.icfi.com/markets/energy/campaigns/wyoming-transmission-reports.

[6] ICF International. March 16, 2011. "Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines." Available at: http://www.ingaa.org/File.aspx?id=12761.

[7] Ela, E., M. Milligan, B. Kirby, E. Lannoye, D. Flynn, M. O'Malley, B. Zavaldi. July 2010. "Evolution of Operating Reserve Determination in Wind Power Integration Studies." Presented at the 2010 IEE Power & Energy Society General Meeting. Available at: http://www.nrel.gov/docs/fy11osti/49100.pdf.

3.1. Increasing cooperation between system operators lowers costs

One of the lowest-cost methods for integrating renewables is increasing cooperation between system operators across the country. The electric power grid represents one of the major infrastructural investments of our time, and there is enormous potential to use this system to distribute renewable energy across the grid.[8] NREL's 2011 Eastern Wind Integration and Transmission Study (EWITS) found that cooperation and consolidation among balancing areas, combined with transmission enhancements, were "the most effective measures for managing wind generation."[9] Smaller balancing authorities were challenged by the high wind levels (20-30 percent) in the EWITS study, and required significant levels of transmission additions. A DOE-funded study of the Southwest Power Pool (SPP), which operates from Northern Texas to Nebraska, also found that large systems significantly reduced the overall integration cost.[10]

This increased cooperation is already happening. PacifiCorp, a utility operating in six Western states, began participation in the CAISO Energy Imbalance Market (EIM) in late 2014, and will be joined by Puget Sound Energy and NV Energy in 2015 and 2016. This market will cover eight states and 44 million people, and will improve the ability of operators in all associated areas to manage renewable integration.[11]

The sheer size of the PJM and MISO systems in the Eastern Interconnect offsets most flexibility constraints posed by aging fossil fleets. In its latest renewable integration study, PJM found it could accommodate up to 30 percent variable renewable energy with no major issues.[12] The regional market in New York, NYISO, is working with neighbors to the east (ISO-NE) and west (PJM) to increase real-time scheduling. In late 2014, NYISO began to implement coordinated transaction scheduling to facilitate transactions across RTO lines.[13] This will lower costs of the system as a whole, better integrating the existing regional resources. Together these three regions represent about 250 GW of generating capacity.

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[8] Luckow, P., B. Fagan, S. Fields, M. Whited. June 19, 2015. "Technical and Institutional Barriers to the Expansion of Wind and Solar Energy." Synapse Energy Economics. Available at: http://synapse-energy.com/sites/default/files/Barriers-to-Wind-and-Solar-15-047_0.pdf.

[9] NREL. 2011. "Eastern Wind Integration and Transmission Study." NREL/SR-5500-47078. Available at: http://www.nrel.gov/docs/fy11osti/47078.pdf.

[10] EPRI. October 2011. "DOE: Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets."

[11] CAISO. 2015. "Energy Imbalance Market Overview." Available at: https://www.caiso.com/informed/Pages/CleanGrid/EIMOverview.aspx.

[12] General Electric International. Feb 28, 2014. "PJM Renewable Integration Study: Executive Summary Report." Prepared for PJM Interconnection. Available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx.

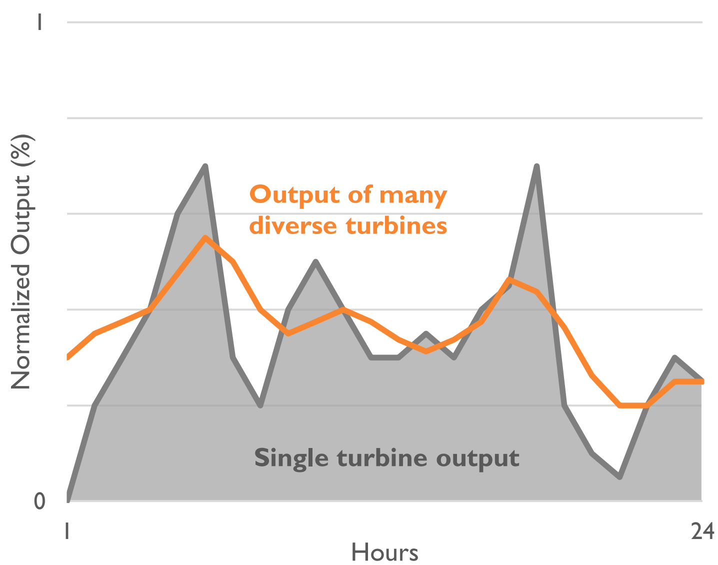
[13] NYISO Coordinated Transaction Schedule available at: http://www.nyiso.com/public/webdocs/energy_future/issues_trends/broader/brm_documents/CTSPamphlet20141003Final.pdf.

3.2. Geographic dispersion reduces swings in renewable generation

System operator coordination can use the broad geographic scope of loads to accommodate swings in wind and solar, but geographically disperse siting of renewable generators themselves can also reduce the incidence of rapid power swings. A recent Lawrence Berkeley National Lab study found that geographic diversity becomes more valuable for wind with increasing penetration, rising from $2.5 per MWh at 20 percent wind energy to $10.6 per MWh at 40 percent.[14]

Figure 3 shows a schematic representation of these values, with the orange line representing a more diverse system. The smoother fluctuations in this system are simple for a system operator to manage.

Figure 3: Representative wind output from many diverse turbines compared to the output of a single turbine



Schematic representation

3.3. Focused transmission investments facilitate renewables integration

The current transmission grid is built around the existing—and aging—fossil infrastructure. New investments are likely needed to facilitate different path flows under a renewables-heavy energy regime. Moderate, focused investments can allow the system to incorporate significant quantities of new energy. The aforementioned PJM integration study found a need for $8 billion in system upgrades

[14] Mills, A. and R. Wiser. March 2014. "Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels." Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6590E-ppt.pdf.

and new lines to facilitate 100 GW of wind energy.[15] MISO has recently undertaken a similar series of transmission projects focused on renewable addition; it is expected that $5-10 billion will be spent on the MVP ("multi-value projects") portfolio to facilitate approximately 10 GW of new wind. Texas, which experienced frequent negative power prices and wind curtailment for several years, has largely solved those problems by designating Competitive Renewable Energy Zones (CREZ), which mandated a number of transmission projects at a cost of $7 billion to facilitate 18.5 GW of wind power. [16]

There is widespread need for new transmission resources across the country, since the location of much of the wind (and some of the solar)[17] resources is different than the locations of most of the older fossil fuel facilities (whose energy output is being displaced, in part, by wind and solar). Such transmission expansions would benefit all ratepayers, and lead to a cleaner and more reliable power system. Distributing these costs accordingly, rather than forcing individual project developers to pay for them, would let a number of relatively smaller (100 MW scale) projects come online.

3.4. Maximizing flexibility of dispatchable units supports intermittent resources

Dispatchable generation is a key resource for integrating intermittent renewable generation. However, there are a number of ways in which a utility has resources that are dispatchable in name only. Steam units typically have minimum loading levels of about half of full output, thereby allowing no more than half of capacity to be useful for integration. Take-or-pay coal contracts or other fuel contracts that substitute fixed cost for variable cost reduce system flexibility by effectively selling it *a priori*.[18] Power plant co-ownership schemes where the utility has no ability to influence the dispatch of that plant result in the lost opportunity to provide flexibility as well.[19]

While existing infrastructure and contracts can't be changed immediately, utilities can make investments in existing steam units to increase their dynamic range, and can weigh a unit's inflexibility when faced with a retrofit or retire decision. Similarly, preserving flexibility of fuel consumption and delivery can avoid imposing integration costs. Finally, the cost efficiencies gained by co-ownership of a

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[15] General Electric International. Feb 28, 2014. "PJM Renewable Integration Study: Executive Summary Report." Prepared for PJM Interconnection. Available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx.

[16] Public Utility Commission of Texas. 2014. "CREZ Progress Report No. 15 (April Update)." Available at: http://www.texascrezprojects.com/page29605717.aspx.

[17] Solar resources are in general more geographically distributed, and potentially located closer to loads, than wind resources and thus in general will not face the same transmission expansion needs as wind resources.

[18] Spinler, S., A. Huchzermeier. "Capacity Options: Convergence of Supply Chain Management and Financial Asset Management." *Risk Management: Challenge and Opportunity*. Berlin: Springer, 2000. 699 – 720.

[19] PGE. March 2014. *2013 IRP Report: Appendix D Wind Integration Study*. Available at: https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp_appD.pdf.

large fossil plant can be undermined in whole or in part if the power generated at the plant is dispatched without consideration of the utility's current need.

3.5. Dispatchable demand-side measures aid in balancing variable supply

On very high load days, demand response offers the potential to meet loads in the shoulder hours, after the sun begins to fall, without imposing minimum loads when solar output is at its peak. Historically, demand response resources have represented load reductions during the highest peak hours of the year. They operate as a dispatchable supply-side resource from the system operator's perspective, being called upon when the price reaches a certain threshold value. In addition to meeting peak loads, demand response resources (when aggregated and automated with fast response times) provide a viable means of balancing the uncertainty of wind and solar resources and reducing ramping requirements.

The PJM study on renewables integration found that demand response resources were a low-cost method to provide reserves in a high-renewables power system. The study tested a case where 1000 MW of generator resources were replaced with demand response in a scenario with 30 percent variable renewable energy. The demand response case reduced production costs by $1.99 per MWh over the course of the year, or $17 million dollars. The study identified demand response as particularly valuable for spinning and regulating reserves—short-term reserves called on to respond in less than 30 minutes.[20]

In addition to increasing the quantity of demand response resources, expanding the flexibility of demand response resources also reduces integration costs. Since 2011, PJM has made a concerted effort to increase the flexibility of the demand response products procured through its capacity market.[21] PJM first introduced two new demand response products—extended summer and annual—that would be available to dispatchers on more occasions, for more hours, at more points throughout the year. As of the 2015 capacity market auction, these products have been redefined again to further increase the flexibility of the products offered within PJM.[22]

Time-of-use rates also have the potential to reduce overall costs to produce power. Milligan et al. found that giving consumers prices more reflective of the real-time market reduced price spikes and increased the value of wind relative to a reference scenario. Better prices both increased demand in low price hours (frequently hours with substantial wind generation) and flattened the number of peak hours to

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[20] General Electric International. Feb 28, 2014. "PJM Renewable Integration Study: Executive Summary Report." Prepared for PJM Interconnection. Available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx.

[21] PJM FERC filing December 2, 2010, Docket ER11-2288-000.

[22] PJM. 2015. "Summary of changes impacting DR capacity performance filing." DRS meeting, January 21, 2015. Available at: http://www.pjm.com/~/media/committees-groups/subcommittees/drs/20150121/20150121-item-06-summary-of-demand-reponse-changes-for-cp.ashx.

periods that better corresponded to when wind was generating. This trend applied to both wind and solar, and value increased with increasing penetration, up to the study's maximum of 40 percent. With PV, demand responsive rates shifted the hours of highest prices to early evening, to correspond with the fall in solar generation.[23]

4. THE HALF-CENT SOLUTION TO WIND AND SOLAR INTEGRATION

As a result of the different operational characteristics of wind and solar resources as compared to conventional fossil resources, power system planners frequently conduct studies to understand the incremental investments and actions needed when more variable renewable energy is added to the system. Integration cost studies have been conducted for decades, but no uniform method for conducting these studies exists. Studies include widely varying sets of operational impacts, and are conducted with widely varying levels of rigor. Beyond variety in how such studies are conducted, required integration measures can vary based on the region of the country, characteristics of the system, and type of resource considered.

A number of integrated utilities directly charge wind and solar generators for integration costs based on such integration studies. Others build these resources themselves, and incorporate integration costs in models used for planning studies. The effect of either approach is to internalize the broader costs to the system that the wind or solar generator itself would not face. Buckley et al. reviewed 19 utilities with 35 distinct charges, sometimes specific to resources or regions, as part of a 2015 study for the Western Interstate Energy Board.[24] Of the 28 integration charges that were specified in terms of energy, 19 were less than $5 per MWh (half a cent per kWh), six were between $5 and $10 per MWh, and three were greater than $10 MWh, based on near-term levels of these resources.

Below we highlight several key studies identified in our own literature review, and interesting conclusions from each. While a number of these studies are very thorough and include reasonable categories of costs, there are several studies with red flags that suggest unrealistic assumptions or costs. These red flags are:

- **Systems operating in isolation**: The electric grid is an enormous existing body of infrastructure and even integrated, independently operating utilities should be able to coordinate with their neighbors.

[23] Mills, A. and R. Wiser. March 2014. "Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels." Available at: http://emp.lbl.gov/sites/all/files/lbnl-6590e.pdf.

[24] Buckley, M., R. Widiss, K. Porter, K. Mansur, K. Starr. 2015. *A Review of Variable Generation Integration Charges*. Denver, Colorado: Western Interstate Energy Board.

- **Inability of existing resources to provide reserves for wind and solar uncertainty:** A number of studies focus on the incremental operating reserves required to manage renewable resource fluctuations. While new gas turbines could provide these reserves, so could existing resources, which are likely operating at somewhat lower levels anyways as a result of the additional renewable energy on the grid.
- **Applying ad-hoc factors from another, unrelated study:** If a utility is going to charge wind and solar generators with an incremental integration cost, that cost should be specific to that system, due to the variability in such studies.

4.1. Wind integration studies

The wind integration cost studies we reviewed in detail are summarized in Figure 4 and Table 1 below. These studies comprise systems ranging from 3,200 MW to 610,000 MW, and wind penetration levels from 2 to 43 percent. Based on the costs of the larger systems in this subset of studies, we generally see costs in the ballpark of $5 per MWh. This compares to the 2014 average levelized power purchase agreement (PPA) price of $23.5 per MWh for wind, or natural gas fuel costs of $35 per MWh.[25]

Synapse reviewed nine wind integration studies. Almost every study was completed under a different process, considering different elements. Some of this is justified by different system characteristics and constraining inputs, but system operators would benefit from agreeing upon a common set of a characteristics to conduct such studies. Despite these differences, interesting conclusions can be drawn from each of these studies, such as:

- Xcel-PSCo's study demonstrated that integration costs are somewhat sensitive to gas prices. Increasing the average gas price from $3.24 per MMBtu to $7.83 per MMBtu resulted in a doubling of integration costs.
- SPP-SERC found it could substantially reduce the level of regulation and contingency reserves required to balance wind when requirements were aggregated across the entire SPP footprint. The Nebraska study came to the same conclusion, and also found that the capacity value of wind resources increased with larger operating areas.
- Many of PGE's units were not allowed to balance renewable energy—coal units were assumed to have zero or nearly zero flexible capacity, and units where PGE only owned a partial share of the unit were not allowed to be used. While this is a legitimate operational challenge, efforts by system planners to reduce these constraints would lower integration costs.
- Minnesota (a part of MISO) found one key driver to be a geographically diverse set of wind resources. A 2014 study did not quantify overall costs in these terms, but demonstrated that 40% of Minnesota's annual sales could be supplied by wind and solar with no unserved load or reserves, with some transmission improvements. Increased penetration of wind and solar led to an increase in the ramping capability of the MISO

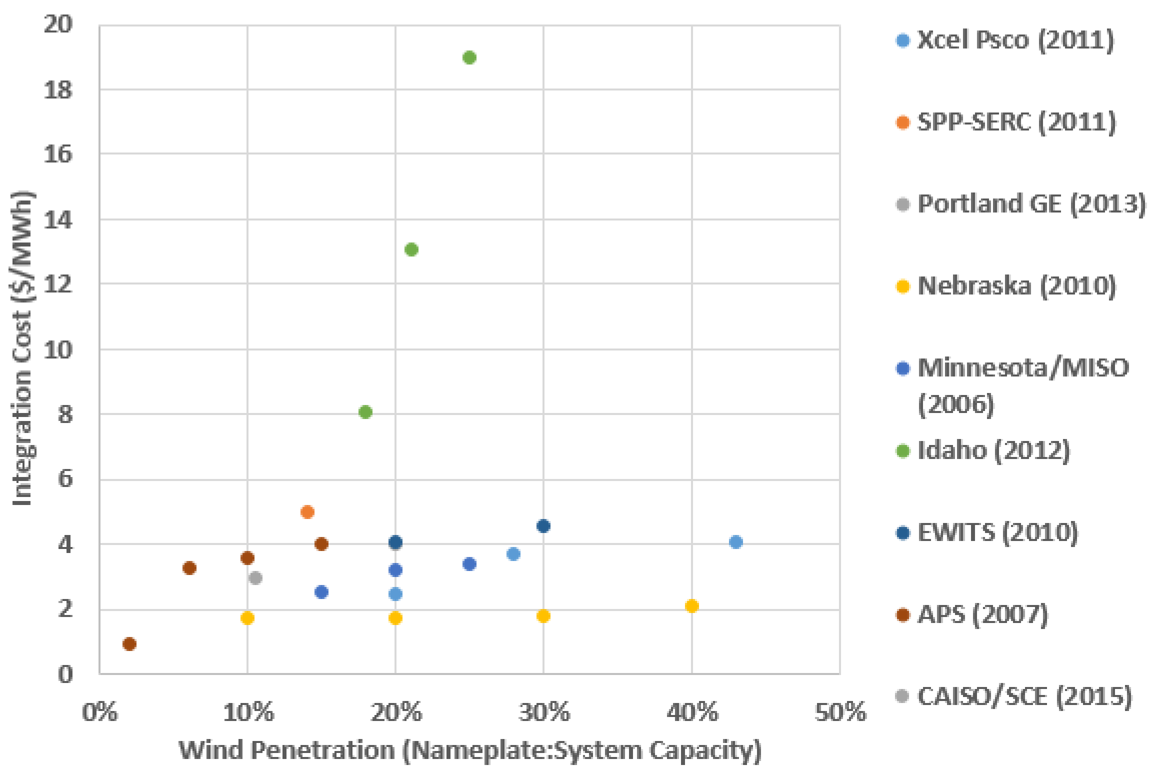
[25] Wiser, R. and M. Bolinger. August 2015. *2014 Wind Technologies Market Report*. Lawrence Berkeley National Laboratory.

fleet, as conventional generation was dispatched down, rather than entirely decommitted, leaving more capacity to be able to ramp up.[26]

- The EWITS study, a study of the entire Eastern Interconnect, largely found low integration costs as a result of broad assumptions about regional cooperation. This integration costs includes the costs implied by uncertainty in the day-ahead commitment as well as additional reserve requirements during hourly dispatch.
- Idaho Power is the outlier of these studies, with integration costs of $8 to $19 per MWh. These high costs result from holding back low-cost hydro power resources to provide balancing reserves for wind and solar, coupled with the fact that while Idaho is well interconnected with the regional electric system, that broader system is not allowed to provide integration services in the model.

Across the board, it is notable that the level of penetration does not seem to be a major driving factor of integration costs, at least below the 30 to 40 percent level reviewed in these studies.

Figure 4: Wind integration cost by level of penetration (reference cases)



Sources for each study can be found with Table 1.

[26] GE Energy Consulting and MISO. October 2014. *Minnesota Renewable Energy Integration and Transmission Study.*

Table 1: Summary of wind integration cost studies

Study	Study period	System Peak (MW)	Wind Penetration (%)	Integration Cost ($/MWh)
Xcel-PSco 2011[a]	2018	7,035	20%	$2.49
			28%	$3.68
			43%	$4.09
SPP-SERC 2011[b]	2022	55,000	14%	$5.00
Portland GE 2013[c]	2018	3,550	20%	$3.57
Nebraska 2010[d]	2018	7,358	10%	$1.72
			20%	$1.74
			30%	$1.81
			40%	$2.10
Minnesota MISO 2006[e]	2020	<14,500	15%	$2.54
			20%	$3.18
			25%	$3.40
Idaho 2012[f]	2017	3,245	18%	$8.06
			21%	$13.06
			25%	$19.01
EWITS 2010[g]	2024	612,150	20%	$3.10 - $5.13
			30%	$4.54
APS 2007[h]	2010	7,900	2%	$0.91
			6%	$3.25
			10%	$3.57
			15%	$4.08
CAISO/SCE 2015[i†]	2024	51,000	10%	$3.01

Sources: (a) Xcel Energy, Inc. and EnerNex Corporation. August 19, 2011. Final Report: Public Service Company of Colorado 2 GW and 3 GW Wind Integration Cost Study. Available at: http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Attachment-2.13-1-2G-3G-Wind-Integration-Cost-Study.pdf. (b) EPRI. October 2011. "DOE: Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets." (c) PGE. March 2014. 2013 IRP Report: Appendix D Wind Integration Study. https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp_appD.pdf. (d) EnerNex Corporation, Ventyx, and Nebraska Power Association. March 2010. "Nebraska Statewide Wind Integration Study." (e) Enernex Corporation & Midwest System Operator. November 2006. "2006 Minnesota Wind Integration Study." (f) Idaho Power. February 2013. "Wind Integration Study Report." (g) National Renewable Energy Laboratory. Revised February 2011. "Eastern Wind Integration and Transmission Study (EWITS)." Prepared by EnerNex Corporation. (h) Arizona Public Service Co. September 2007. "Arizona Public Service Wind Integration Cost Impact Study." Prepared by Northern Arizona University. (i) SCE. May 29, 2015. "Report of Southern California Edison Company on Renewable Integration Cost Study for the 33% Renewables Portfolio Standard." Rulemaking 13-12-010.

† SCE tested 1,000 MW renewable increments above the RPS portfolio. Wind penetration estimated based on assumed 2024 RPS portfolio.

4.2. Solar integration studies

A more limited number of solar integration studies exist, largely as a result of the more recent cost declines, to the point where systems are now considering much larger levels of solar energy than they were four or five years ago. Synapse summarizes the results of five studies in Figure 5 and Table 2 below.

Integration costs are similar to or lower than costs using similar metrics for wind energy, perhaps contributed by the relatively low penetration values assumed and/or the additional capacity value associated with solar capacity.

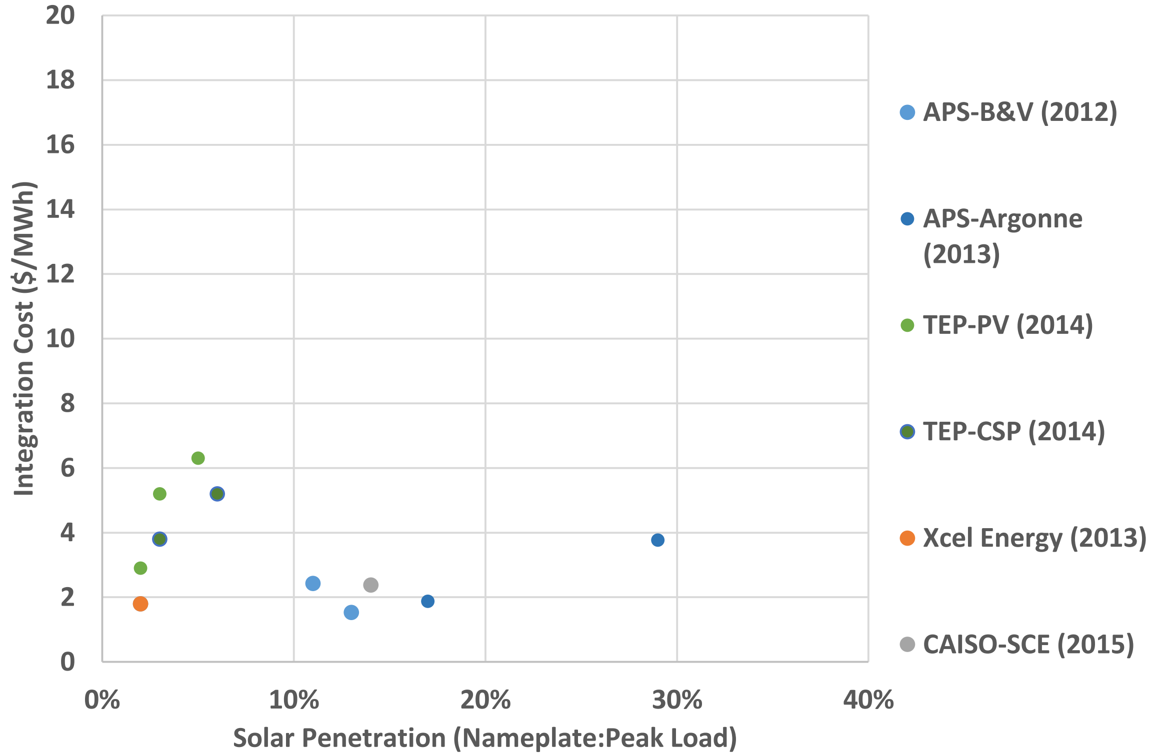
Interesting anecdotes from these studies include:

- Two groups conducted integration studies for Arizona Public Service (APS), with different primary challenges for integration. The Black & Veatch (B&V) study found that integration costs where driven by increased operating (spinning) reserves and minor increases in incremental energy costs. The Argonne study found the inflexible nature of the existing coal and nuclear generation fleet to be a driving factor. Integration costs were more than halved by assuming an increasing amount of ramping from nuclear power plants, decreasing from \$3.88 per MWh to \$1.74 per MWh.

- Tucson Electric Power (TEP) looked at concentrated solar power (CSP), PV, and wind resources in 100 MW increments, and found that wind was substantially less expensive than both solar resources, and CSP was much easier to integrate then PV, as a result. These costs were based on inter-hour fuel costs to make the renewable profiles comparable to a flat-block purchase, and did not incorporate additional system regulation costs.

- Xcel Energy, which operates in Colorado, looked exclusively at distributed PV and focused on increasing utilization of gas resources to balance intermittency. As a result, the cost values were sensitive to gas prices, similar to its wind integration study.

Figure 5. Solar integration costs by level of penetration



Source: Sources for each study can be found with Table 2.

Table 2: Summary of solar integration cost studies (reference cases)

Study	Study Period	System Peak (MW)	Type of Solar	Penetration on Peak Demand Basis (%)	Integration Cost ($/MWh)
B&V - APS 2012[a]	2020	8,200	PV	13%	$1.53
	2030	10,900	PV	11%	$2.43
Argonne – APS 2013[b*]	2027	10,090	PV	17%	$1.88
	2027	10,090	PV	29%	$3.77
TEP IRP 2014[c]	2014-2028	3,198	PV	2%	$2.90
	2014-2028	3,198	PV	3%	$5.20
	2014-2028	3,198	PV	5%	$6.30
	2014-2028	3,198	CSP	3%	$3.80
	2014-2028	3,198	CSP	6%	$5.20
Xcel Energy 2013[d]	2012-2034	8,000	DG PV	2%	$1.80
CAISO-SCE 2015[e†]	2024	51,000	PV	14%	$2.38

Sources: (a) Black & Veatch. November 2012. "Solar Photovoltaic Integration Cost Study." B&V Project No. 174880. Prepared for Arizona Public Service. (b) Mills, A., A. Botterud, J. Wu, Z. Zhou, B-M. Hodge, M. Heaney. October 2013. "Integrating Solar PV in

Utility System Operation." Report ANL/DIS-13/18, Argonne National Laboratory. (c) Tucson Electric Power. April 2014. Tucson Electric Power 2014 Integrated Resource Plan. Available at: https://www.tep.com/doc/planning/2014-TEP-IRP.pdf. (d) Xcel Energy Services. May 2013. "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." (e) SCE. May 29, 2015. "Report of Southern California Edison Company on Renewable Integration Cost Study for the 33% Renewables Portfolio Standard." Rulemaking 13-12-010.

**Argonne's study did not indicate the system peak assumed for the study; as a result, the penetration levels presented are based on system peaks used by the B&V report.*

[†] SCE tested 1,000 MW renewable increments above the RPS portfolio. Wind penetration estimated based on assumed 2024 RPS portfolio.

5. CONCLUSIONS

Electric system operators are already managing a rapidly growing influx of variable renewable energy, and are preparing to integrate even larger levels. As penetration of wind and solar becomes more substantial, system operators will have to improve coordination with their neighbors, reduce the quantity of inflexible generation on their systems, and be able to compensate for forecast errors from system resources outside their control.

Improved coordination between neighboring system operators is already underway, from California and its neighbors in the West to New York, New England, and PJM in the East and Northeast. More work needs to be done, but this is one area where substantial progress can be made without associated incremental investments in new technologies.

Several new technologies can help to balance the rapid swings in variable resource generation, including both expected solar declines at the end of the day and unexpected swings due to forecast errors. Demand response is becoming better automated than it was in the past, and can provide rapid response to major events. Updated rate structures can also encourage customers to use energy in patterns that are easier for system operators to incorporate. Battery, pumped hydro, and compressed air storage all offer the potential to store renewable energy in high generation (and correspondingly low price) hours, and dispatch it when needed most.

These adjustments are already underway, well understood, and can be planned for in the existing context of long-term system planning. These measures do pose an incremental cost on the system, though most studies indicate this cost is relatively small, on the order of half a cent per kWh of energy for either wind or solar. Despite differences in the types of systems across the country, some composed of much more inflexible coal or nuclear generation than others, costs appear to follow similar bands for most systems. Much of the difference in integration costs can be explained by methodological differences in studies. System planners should conduct their own studies of how they will integrate new resources, with the knowledge that most systems see costs below half a cent per kWh. Integration is not a reason to put the brakes on a rapid expansion of low-cost wind and solar resources.