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REGULATORY ASSISTANCE PROJECT

Getting the Most Out of Low-Cost Solar and Wind: Seven Strategies for State Regulators

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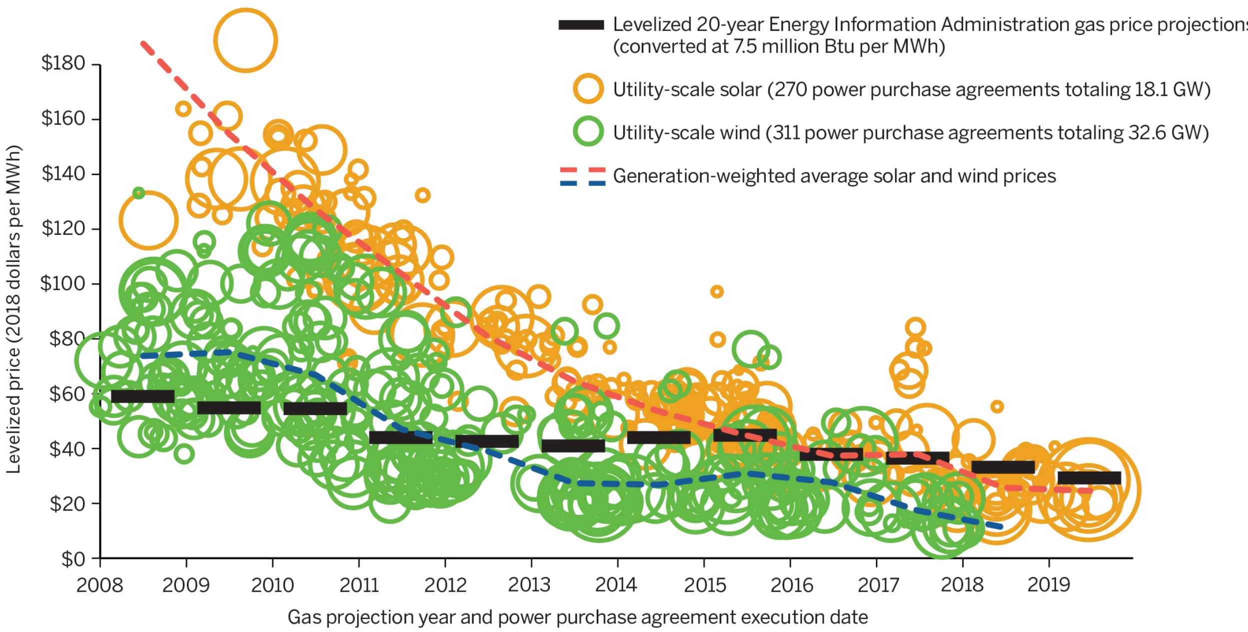
Introduction

Solar and wind generation costs have declined dramatically over the past decade, creating new opportunities for electric utilities and their customers. In a growing number of regions, levelized costs for solar and wind generation have fallen below the fuel cost of less efficient coal-fired and even gas-fired power plants (see Figure 1; Bolinger et al., 2019[1]), indicating that it can be cheaper to construct new solar and wind generators than operate existing plants.

Figure 1. Cost of solar and wind power drops below fuel cost for many gas-fired plants



Source: Bolinger, M., Seel, J., and Robson, D. (2019). *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States*

In this rapidly evolving environment, electricity providers should be actively in the market for low-cost solar and wind. Vertically integrated utilities, however, have often been slow to take advantage of these resources.

In principle, utility regulation should aim to promote outcomes that are consistent with the dynamic efficiency of a competitive market. That is, regulation should facilitate investments in new lower-cost resources that replace existing higher-cost resources, potentially through early retirements. We suggest public utility commissions (PUCs) consider adjusting regulatory frameworks — from integrated resource planning to fuel cost adjustment mechanisms — on an ongoing basis to enable this process of technological

[1] Market prices for natural gas and coal fell in the first half of 2020, but the U.S. Energy Information Administration expects a recovery by 2021. See U.S. Energy Information Administration (2020).

change to occur, ensuring just and reasonable rates for utility customers.

This paper outlines seven practical strategies — a comprehensive toolkit that PUCs can use to reduce obstacles to the benefits of technological change and focus on more rapid utility acquisition of low-cost solar and wind.

The seven recommended strategies are:

1. **Address stranded costs:** Provide assurance that stranded costs of retiring generating units displaced by low-cost wind and solar will be recoverable.
2. **Level the IRP playing field:** Update integrated resource plan (IRP) rules on resource evaluation to ensure that renewable resources are evaluated on a consistent and comparable basis with conventional resources.
3. **Make retirement checkups routine:** Provide guidance requiring utilities to regularly and systematically evaluate generator retirements in IRPs.
4. **Speed up the cycle:** Increase the frequency of resource planning and acquisition.
5. **Go all-source:** Require utilities to use all-source competitive solicitations to acquire new resources.
6. **Revisit the fuel cost pass-through:** Give utilities more awareness of the fuel cost risks of fossil-fired generation by reforming fuel cost adjustment mechanisms.
7. **Think regionally:** Encourage utilities to join a regional transmission organization or energy imbalance market.

These seven strategies are complementary, although some may be more applicable than others in different states due to differences in industry structure, markets and regulatory practices. Regulators will need to weigh trade-offs and develop approaches that are workable within their state's legal and regulatory frameworks.

Strategy 1: Address stranded costs

Provide assurance that stranded costs of retiring generating units displaced by low-cost wind and solar will be recoverable

Utilities are often concerned that more rapid acquisition of low-cost solar and wind generation will lead PUCs to deem existing generation assets no longer "used and useful," leaving utility shareholders to absorb the costs of early retirement.[2] As a result, utilities may not support — or may actively resist — uptake of solar and wind generation. An important step in assuaging these concerns is to assure utilities they will be able to recover

[2] For an overview of issues in the context of a case study of Colorado, see Lehr (2018).

prudently incurred costs associated with assets being retired for economic reasons. In an environment where it is cheaper to construct new solar and wind generators than operate existing plants, such assurances should also benefit ratepayers, although, as always, care will need to be exercised in valuing stranded assets and sharing of savings.[3]

The roots of utility concerns lie in their asset mixes and incentive structures. As of 2018, 13% of the current U.S. generation fleet consists of utility-owned coal (113 GW nameplate) and natural gas (45 GW) steam units that were built before 1980 (U.S. Energy Information Administration, n.d.).[4] These units often have very long depreciation lifetimes. Although their book depreciation at the time of construction may have been around 30-40 years, renovations, renewals, replacements and pollution control investments can extend the depreciation lifetimes of these plants to 50-60 years, and, in principle, ongoing investments can extend their lifetimes indefinitely.

Vertically integrated utilities do not face the same competitive pressures as independent power producers, instead earning regulated cost recovery for, and a regulated return on, generation assets. As a result, utilities often have little incentive to seek out replacements for existing assets, even when the underlying economics allow for cost savings. Even if new low-cost alternative resources are available, utilities may decide not to acquire new resources to ensure that existing assets meet a "used and useful" criterion and are not at risk of cost disallowance. Regulatory requirements that utilities procure new resources competitively may also provide a disincentive to acquire new resources by raising concerns that it will shrink the utility rate base. Extending the lifetime of existing assets is thus often the path of least resistance for utilities.

Providing cost recovery assurances is an initial step in assuaging utility concerns, enabling the process of technological change to occur — in this case newer, lower-cost generation replacing older generation. PUCs can provide these kinds of assurances more formally or in individual resource planning or acquisition proceedings. For instance, in a notice of proposed rulemaking on state resource planning, Colorado regulators responded to utility concerns around retroactive prudence determinations by clarifying that, "Generation assets are long-lived and capital intensive, and retroactive prudency determinations are counter to Colorado utility regulation and the public interest" (Colorado Public Utilities Commission, 2018-b). The commission proposed a focus on "prospective" prudence — whether utility retirement and acquisition decisions going forward are prudent — rather

[3] For discussion of sharing fuel cost savings, see Strategy 6.

[4] Utilities include investor-owned, public and rural cooperative utilities.

than whether past investments are prudent relative to current costs.[5]

Providing cost recovery assurances does not necessarily require deciding beforehand on the mechanisms for utilities to recover any stranded costs and share the cost savings from replacing existing assets.[6] Without this first step, it may be difficult to effectively deploy the other strategies in this paper and align utility incentives with market trends.

Strategy 2: Level the IRP playing field

Update IRP rules on resource evaluation to ensure that renewable resources are evaluated on a consistent and comparable basis with conventional resources

Most investor-owned utilities have an integrated resource planning process. An IRP is a 10- to 20-year vision for how utilities will reliably meet projected demand and regulatory requirements at low cost and with acceptable risk (Wilson & Biewald, 2013; Lazar, 2016). IRPs play an important role in identifying utilities' resource needs; developing a consensus view of regulatory requirements, costs and other trends; identifying and managing potential risks; and, in some cases, establishing a basis for the prudence of utility decision-making.

Historically, utilities often fixed the amount of solar, wind and other renewable resources in their IRP resource portfolios at levels that ensured compliance with state renewable portfolio standards or other renewable goals (Kahrl et al., 2016).[7] This approach was reasonable when the cost of renewable generation was significantly higher than the cost of conventional generation.

As the cost of solar and wind generation becomes increasingly competitive with conventional generation, utility IRP practices should shift from this compliance-based approach to one that allows wind and solar generation to be added in amounts that result in least-cost resource portfolios, which may exceed state renewable energy mandates. Some utilities continue to use the compliance-based approach in their IRPs, however.[8] "Mainstreaming" solar and wind generation in utility planning — leveling the playing field with other resources — may require updates to IRP rules.

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[5] A focus on prospective prudence does not necessarily assume that all historical utility investments were prudent, which would further goals of technological progress at a cost of moral hazard (Harunuzzaman et al., 1994). Rather, it focuses on whether a utility could have reasonably known at the time of investment that the investment would later become unused and unuseful and whether the utility makes prudent decisions going forward.

[6] For more on potential mechanisms, see Benn et al. (2018), Varadarajan et al. (2018) and Lehr & O'Boyle (2018).

[7] A notable exception is Puget Sound Energy's 2005 IRP, which found that wind was the most cost-effective resource independent of any resource mandate. The Wild Horse wind power project was completed in 2006 under this IRP.

[8] For example, see Ameren Missouri (2017) and Duke Energy Progress (2019).

PUCs' IRP rules provide the regulatory framework for utility planning. They guide the planning process, resource evaluation methods and content of the IRP report. As technologies change, IRP rules must be updated to keep pace. For instance, New Mexico updated its IRP rule to require utilities to consider energy storage in their IRPs (New Mexico Public Regulation Commission, 2017).[9]

For solar and wind generation, IRP rules can facilitate mainstreaming of these resources by requiring utilities to evaluate all resources on a comparable and consistent basis. "Consistent evaluation" refers to the use of consistent assumptions across the evaluation of different resources. "Comparable evaluation" refers to equivalent evaluation of different technologies, resource locations, ownership and contract options, and lead-in times and start dates. Examples of PUC IRP rules that require consistent and comparable evaluation include Oregon's IRP guidelines, which explicitly state, "All resources must be evaluated on a consistent and comparable basis" (Oregon Public Utility Commission, 2007), and the Indiana Utility Regulatory Commission's rule that "Supply-side and demand-side resource alternatives must be evaluated on a consistent and comparable basis in the selection of the preferred resource portfolio."[10]

Applying IRP rules for consistent and comparable evaluation requires ongoing efforts by PUCs to ensure that utilities are adhering to this principle and using state-of-the-art evaluation frameworks and methods (see the text box on Page 8). Monitoring utility compliance with the rules can be difficult, as PUCs are often not sufficiently staffed to evaluate the details of IRPs, though PUCs can solicit input and expertise from third-party intervenors and experts to assist with compliance.

In reviewing the treatment of solar and wind generation in utility IRPs, PUCs can focus on the following four key areas.[11]

Net Value and Portfolio Value

Because the value of solar and wind generation is time- and location-dependent and interactive with other resources, utilities should focus on the net value — market value plus other benefits minus costs — of these resources as part of an overall resource portfolio, rather than levelized cost comparisons among individual resources. A state-of-the-art modeling framework can enable net value comparisons among different resources. Again, to make meaningful comparisons, utilities should not impose artificial limits on the selection of solar and wind generation as part of a least-cost resource portfolio.

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[9] For other examples of IRP rule updates, see Wilson & Biewald (2013).

[10] For a description and application of these rules, see Stanton et al. (2019).

[11] For overviews of the issues and challenges associated with modeling renewable energy, see Mai et al. (2013), Sullivan et al. (2014), Kahrl et al. (2016) and Go et al. (2020).

Resource Adequacy Value

Undervaluing solar and wind generation's contribution to long-term resource adequacy may result in underinvestment in solar and wind and excess generation capacity. Independent system operators and regional transmission organizations (ISOs/RTOs), utilities and state agencies are increasingly using probabilistic methods to calculate capacity credits for solar and wind resources (North American Electric Reliability Corporation, 2011). In ISO/RTO markets, ISOs/RTOs' capacity credits for solar and wind used in their resource adequacy programs will often be only for a near-term time horizon, which means that utilities that participate in these markets must still manage the longer-term risk associated with the capacity value of solar and wind generation.

Risk Management

The lack of fuel costs and emissions are important benefits of solar and wind generation. The benefits of not having to face fuel price risk and the risk of future emissions regulation should be fully recognized in IRPs. Many utilities do include some form of risk analysis in their IRPs (Kahrl et al., 2016), though these differ in their sophistication and utilities often do not have adequate incentives to fully account for these risks in their IRPs or their acquisition of new resources.

Integration Cost Adders

Some utilities add costs to solar and wind generation in their IRPs to account for the incremental system costs of these resources that may not be sufficiently captured in planning models.[12] Utilities have often not been rigorous in calculating these cost adders, although they have generally been low (Mills & Wiser, 2012). If utilities do use integration cost adders for solar and wind generation, these adders should be based on a rigorous, utility-specific analysis rather than values from the literature. For utilities that participate in bid-based ISO/RTO markets, there is no justification for using integration cost adders.

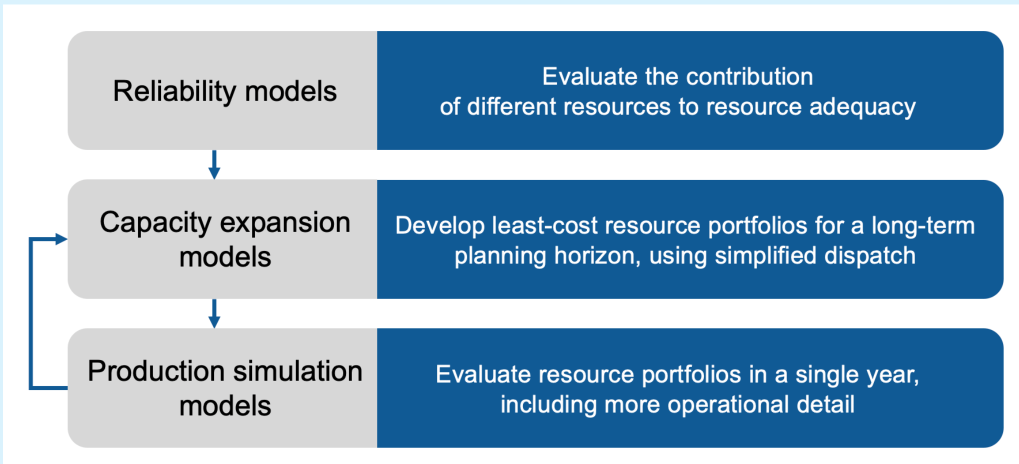
Requiring utilities to evaluate all resources on a comparable and consistent basis does not mean abandoning state policy goals. State policy goals can still function as minimum requirements in resource portfolios, even when IRP rules require comparable and consistent evaluation.

[12] Examples of integration costs include startup, ramping, heat rate penalty, curtailment and congestion costs.

Understanding utility modeling tools

In general, best-practice evaluation of solar and wind generation in an IRP will include a combination of three modeling tools: (1) reliability models, (2) capacity expansion models and (3) production simulation models (Figure 2). Reliability models estimate the contributions of solar and wind generation to resource adequacy.[13] Outputs from reliability models are used in capacity expansion models.

Figure 2. Three tools for best-practice evaluation of solar and wind generation



Capacity expansion models are used to identify least-cost portfolios for a planning horizon — for instance, 20 years — under different scenarios. Each scenario features a different set of assumptions for demand, technology costs, fuel prices and other important variables. Because the scenarios consider a longer time horizon, capacity expansion models have a simplified dispatch and either a simplified or no representation of the transmission system to ensure computational tractability. Production simulation models are used to consider more detail for a shorter period under one or more scenarios. They typically assess the operational performance and cost of portfolios for a year at a time, often with hourly dispatch and more detailed representation of transmission constraints.

Production simulation models perform two additional functions. They are used for risk analysis, by developing a distribution of possible operating costs for a resource portfolio based on a large number of model runs, where assumptions about fuel cost and other factors are allowed to vary in each run. Production simulation models are also used to develop adders and other inputs for capacity expansion models to capture benefits and costs not incorporated in capacity expansion models.

[13] For examples of reliability studies for solar and wind generation, see Public Service Company of Colorado (2016) and PacifiCorp (2019). In organized markets, utilities may rely on the ISO/RTO's capacity credit values used for capacity markets, though these values are not long-term forecasts, which means that utilities are exposed to the risk that these capacity credit values change over time.

Strategy 3: Make retirement checkups routine

Provide guidance requiring utilities to regularly and systematically evaluate generator retirements in IRPs

Utilities often evaluate both planned and early (accelerated) generator retirements in their resource plans. Evaluation of early retirements, however, is typically through one-off, unit-specific scenarios. For instance, a utility might develop and evaluate a scenario where a unit that has environmental compliance requirements is retired before its planned retirement date instead of making the capital investments needed for environmental compliance. These one-off evaluations are generally neither structured nor systematic. Utilities often lack guidance from PUCs on when and how they should evaluate early retirement of existing units in their resource plans (Wilson & Biewald, 2013).

Two recent examples of the usefulness of integrating retirement decisions into IRPs come from Colorado and Indiana; the latter also provides one approach to doing so. The Colorado example illustrates why more structured and systematic analysis of retirements can be helpful in aligning stakeholders. In 2016, the Colorado Public Utilities Commission approved phase I of the Public Service Company of Colorado (PSCo) electricity resource plan but required PSCo to evaluate and present two additional demand scenarios in phase II.[14] PSCo filed for permission to evaluate a third scenario in phase II: the Colorado Energy Plan portfolio, which would include retirement of two units at the Comanche coal-fired generating station. PSCo would use bids from the solicitation to evaluate cost-effectiveness.

The Colorado PUC ultimately approved the Colorado Energy Plan due to the availability of low-cost bids in PSCo's all-source competitive solicitation, including additional coal unit retirements above those anticipated in the electricity resource plan. PUC staff, ratepayer advocates and other stakeholders criticized PSCo's approach, however, because the utility used assumptions in evaluating the Colorado Energy Plan that staff and stakeholders believed were unrealistic and inconsistent with the PUC-approved values in its electricity resource plan (Colorado PUC, 2018-a). More systematic analysis of retirement decisions in the resource plan could have facilitated greater consensus among stakeholders.

The second example, from Indiana, illustrates one approach to more systematic analysis of

[14] Colorado's electricity resource plan process consists of two phases. Phase I consists of a resource acquisition plan based on assumed costs for generic new resources, which the PUC reviews and may approve with or without modifications. Phase II consists of a competitive all-source solicitation, and the PUC issues a final decision that approves, conditions, modifies or rejects the utility's preferred plan based on actual solicitation results. See Colorado PUC (2018-a).

generator retirements. In its 2018 IRP, Northern Indiana Public Service Co. (NIPSCO) developed a two-step process for integrating the evaluation of retirement decisions (NIPSCO, 2018). In the first step, the company conducted a retirement analysis of its five remaining coal plants, developing eight plausible retirement scenarios to frame the IRP analysis. The scenarios differed in the number of units to be retired and when. In the second step, NIPSCO developed least-cost resource portfolios to replace coal units and meet demand growth using a capacity expansion model. An important change in NIPSCO's 2018 IRP, relative to its 2016 IRP, was to use results from an all-source competitive solicitation, conducted earlier in 2018, rather than the reference cost of combined cycle gas turbine, to evaluate replacement portfolio costs for retirements (Stanton et al., 2019).

NIPSCO evaluated the retirement scenarios using a scorecard that included cost, risk, reliability, employment and local economy considerations (see Table 1; NIPSCO, 2018). NIPSCO's preferred plan (scenario 6 in Table 1) included the retirement of a significant amount of its coal units.

Table 1. NIPSCO's retirement scorecard and preferred retirement path

Scenario	3	4	5	6	7	8
Portfolio transition target:	15% coal by 2028 with ELG*	15% coal by 2028 without ELG*	15% coal in 2023 (Michigan City 2035)	15% coal in 2023 (Michigan City 2028)	15% coal by 2023	0% coal in 2023
Cost to customer	$12,455 +$1,481 13.5%	$12,336 +$1,361 12.4%	$11,454 +$479 4.4%	$11,343 +$369 3.4%	$11,187 +$213 1.9%	$10,974 -$ -%
Cost certainty	$12,622 +$1,490 13.4%	$12,502 +$1,370 12.3%	$11,634 +$502 4.5%	$11,504 +$372 3.3%	$11,295 +$163 1.5%	$11,132 -$ -%
Cost risk	$13,225 +$1,569 13.5%	$13,105 +$1,449 12.4%	$12,252 +$596 5.1%	$12,045 +$389 3.3%	$11,750 +$93 0.8%	$11,656 -$ -%
Reliability risk	Acceptable	Acceptable	Acceptable	Acceptable	Not acceptable	Not acceptable
Employees	125	125	276	276	276	426
Local economy	($23 million) (9%)	($31 million) (12%)	($65 million) (26%)	($74 million) ($29%)	($74 million) (29%)	($94 million) (37%)

* ELG = effluent limit guidelines

For the sake of readability, this table omits two scenarios for 65% and 40% coal portfolios.

Source: Northern Indiana Public Service Co. (2018). *2018 Integrated Resource Plan*

An alternative approach would be to ask the capacity expansion model to identify least-cost retirement dates (i.e., "endogenize" retirement decisions). This approach would likely raise concerns among utilities, due to the narrower focus on costs and simplified nature of capacity expansion models, though it could provide additional information to PUCs on the economics of retirement decisions that could be verified by additional analysis.

In general, utility concerns around reliability risks from early generator retirements should be substantiated with quantitative evidence. For instance, NIPSCO's use of "acceptable" and "unacceptable" reliability risk in Table 1 does not, without additional evidence, provide regulators and stakeholders with a basis for determining that the reliability risk would exceed the $369 million in expected cost savings from shutting down the utility's remaining coal plants (scenario 6 versus scenario 8).

Retirement decisions are complex, involving a range of socioeconomic, transmission system reliability, decommissioning cost and regulatory risk factors that go beyond the narrower calculus of utility resource costs. Additionally, there are many possible permutations of the number and timing of retirements. Analysis of retirement decisions thus may not lend itself to a textbook, one-size-fits-all approach.

At a minimum, PUCs can require utilities, through IRP rules or specific guidance, to regularly and systematically analyze unit retirements in their resource plans. For instance, PacifiCorp included a systematic study of coal retirements in its 2019 IRP, driven partly in response to Oregon PUC requirements, which led to cost-effective early retirements of coal generation (PacifiCorp, 2019). PUCs can also require utilities to consider the employment and local economic impacts of generator retirement decisions.

Strategy 4: Speed up the cycle

Increase the frequency of resource planning and acquisition

Utilities undertake resource planning and acquisition at regular intervals, as stipulated by legislation or regulation. Resource acquisition — for instance, through competitive solicitations (see Strategy 5) — is typically triggered by needs identified through resource plans. Ideally, the timing of resource planning cycles should reflect a balance between the significant effort and cost involved in executing a planning cycle and the need for ongoing portfolio adjustment for changing conditions.

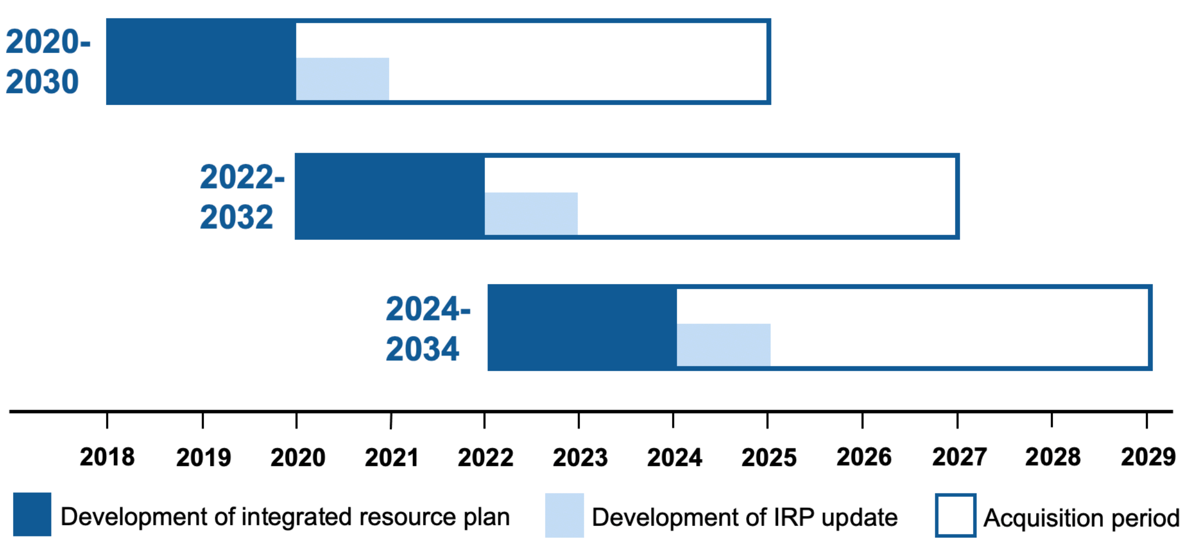
In an era of rapid technological change — including rapidly falling costs of wind and solar resources — and uncertainties regarding demand, there is a strong argument for shortening the planning cycle and requiring annual IRP updates (and increasing their scope). Utilities should also be required to undertake and file IRPs and IRP updates even if they do not anticipate load growth or expect any new resource retirements.

Changes in technology costs can have a significant impact on utility resource retirement and acquisition plans, even over a relatively short time frame. For example, in the four-year span between PSCo's 2013 and 2017 all-source competitive solicitations, wind and solar bid prices declined more than 50% (PSCo, 2013; PSCo, 2017).[15] The number of bids PSCo received for standalone or paired battery storage increased from one in 2013 to 133 in 2017. The potential for these kinds of rapid changes in technology and technology costs illustrates the benefit of more frequent resource planning and acquisition cycles in helping to smooth changes in resource mix over time.

In principle, a two-year planning and competitive solicitation process with annual planning updates can balance the need for transparency, analytical rigor, and commission and stakeholder review with the benefits of more frequent planning and resource acquisition. Moving to a shorter utility resource planning and acquisition cycle might be an enhancement for states that have longer cycles, with the benefits of more quickly identifying cost-saving opportunities outweighing the greater burdens on utility planning teams and commissions and stakeholders who have to review documents.

Figure 3 shows an illustrative planning and acquisition process with a two-year cycle. It features a biennial IRP process, competitive solicitations occurring at the end of each IRP filing, annual IRP updates, and a five-year acquisition period. The acquisition period sets the time horizon over which the utility will acquire new resources.

Figure 3. Illustrative integrated resource planning process



[15] Reported bid prices in these two solicitations are not directly comparable because 2013 bids were estimated "all-in" prices (e.g., including estimated incremental transmission costs) and reported as a range, whereas the 2017 were median bid prices. The 50% decline here is a conservative ballpark estimate.

In determining whether to increase the frequency of planning and procurement, PUCs can weigh potential benefits and costs. Cycles longer than two years risk missing opportunities to save money as technology costs fall. Annual cycles may be feasible, but elements of the process may be too compressed. Competitive solicitations may be more difficult to undertake on an annual basis but might be feasible for some states, depending on regulatory requirements and PUC staffing constraints.

Several states currently have two-year resource planning cycles, although many are on longer cycles. Table 2 shows the timing for select states (based on Wilson & Biewald, 2013, and Michigan Public Service Commission Staff, 2017).[16] At one extreme, the Hawaiian Electric Co.'s integrated grid planning process has an 18-month cycle (Hawaiian Electric Co., n.d.); at the other, Michigan requires utilities to produce resource plans only every five years (Michigan Public Service Commission, n.d.).

Table 2. Frequency of resource planning cycles for select states

Planning frequency	States
Less than two years	Hawaii
Two years	Arizona, Idaho, Indiana, Minnesota*, Montana, North Carolina, North Dakota, Oregon, Utah, Virginia, Washington, Wisconsin
Three years	Arkansas, Georgia, Kentucky, Louisiana, Missouri, Nevada, New Mexico, Oklahoma, Vermont
Four years	Colorado
Five years	Michigan

* Minnesota's suggested frequency is two years, but the requirement is flexible to utility plans and size (Minnesota Public Utilities Commission, n.d.).

Sources: Wilson, R., and Biewald, B. (2013). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*; and Michigan Public Service Commission Staff. (2017). *IRP Requirements for MISO States*

Between full (comprehensive) IRPs, some states require utilities to conduct interim updates of their IRPs. For instance, North Carolina requires utilities to produce a comprehensive IRP every two years and file annual updates that include an updated 15-year forecast of demand, resource retirements and new resource additions (North Carolina Utilities Commission, n.d.). At the other end of the spectrum, many states allow utilities to defer submission of a resource plan if utilities do not expect to add new resources.

[16] The authors confirmed this information based on a search of IRPs.

Strategy 5: Go all-source

Require utilities to use all-source competitive solicitations to acquire resources

In some states, utilities are required by law or regulation to acquire new resources through competitive solicitations.[17] In a subset of these states, competitive solicitations are "all source," meaning that most or all resource types and technologies are allowed to compete in the solicitation.

All-source competitive solicitations, and competitive utility procurement more broadly, came into vogue in the 1980s as an alternative to avoided-cost-based procurement under the Public Utilities Regulatory Policy Act (Rose et al., 1991; Swezey, 1993). Over time, utility procurement became more specialized, often with separate processes for conventional generation, renewable generation, demand-side resources and energy storage.

In an era of rapid technological change, all-source competitive solicitation has many advantages. It can enable price discovery across a range of technologies, helping to reduce uncertainty about the relative costs of each. It can encourage innovations in generation-storage pairing and in contractual arrangements.[18] It also helps utilities to identify and capture the value of interactive effects among solar, wind and batteries.

Utilities and regulators have shown renewed interest in all-source competitive solicitation: At least 14 utilities conducted such solicitations during the 2010s (Kahrl, forthcoming). These recent all-source competitive procurements illustrate its value. For example, PSCo's 2017 all-source competitive solicitation resulted in a large number of bids, which the Colorado PUC called "exceptionally low" (2018-a). Many of these bids featured innovative pairings of battery storage with wind and solar resources (PSCo, 2017). Solicitations by El Paso Electric and NIPSCO produced similar results. All three of these solicitations resulted in significant procurement of low-cost wind and solar generation, as shown in Table 3 on the next page (PSCo, 2017; NIPSCO, 2018 and 2019; El Paso Electric, 2019; Colorado PUC, 2018-a).

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[17] Surveys during the late 2000s (Basheda and Schumacher, 2008; Tierney and Schatzki, 2009) found between 10 and 13 states with policies requiring or encouraging electric utilities to use competitive procurement to acquire new resources.

[18] For instance, in all-source solicitations utilities will need to formulate contractual terms and conditions that can accommodate a broad range of potential generation, storage and demand-side resources. Developers can also propose innovative risk sharing mechanisms in their bids.

Table 3. Bid prices and selected portfolios for three recent all-source competitive solicitations

Utility, solicitation year	Wind, solar and battery bid prices	Selected portfolio
El Paso Electric, 2017	Not disclosed	Solar: 200 MW Battery storage: 100 MW Gas combustion turbine: 226 MW Additional solar and wind: 50-150 MW
PSCo, 2017	Solar: $29.50/MWh Wind: $18.10/MWh Battery storage: $11.30/kW-month *(Median bid prices)*	Wind: 1,131 MW Solar: 707 MW Battery storage: 250 MW Gas: 383 MW
NIPSCO, 2018	Solar: $35.67/MWh Wind: $26.97/MWh Battery storage: $11.24/kW-month *(Average bid prices)*	Wind: 1,104 MW

Sources: Bid prices from Public Service Company of Colorado. (2017, December 28). *2017 All Source Solicitation 30-Day Report*; and Northern Indiana Public Service Co. (2018). *2018 Integrated Resource Plan.* Results from El Paso Electric. (2019, January 21). *Plans to Add Hundreds of MWs of Solar Energy, Battery Storage by 2023;* Colorado Public Utilities Commission. (2018, August 27). Proceeding No. 16A-0396E, Decision No. C18-0761; and Northern Indiana Public Service Co. (2019). *NIPSCO Announces Addition of Three Indiana-Grown Wind Projects*

As with utility competitive procurement more broadly, developing a fair and efficient process for all-source competitive procurement requires significant time and effort from PUCs and utilities. An emphasis on good process can foster confidence in the integrity of the competitive solicitation, which in turn is important for obtaining competitive and innovative outcomes (Lehr, 2019). Designing for a fair process includes consideration of transparency requirements, resource participation rules, bidder requirements, stakeholder participation, timelines and evaluation methods. Fortunately, there is an increasing number of case studies that PUCs and utilities can use to design and implement all-source competitive procurement (Wilson et al., 2020; Kahrl, forthcoming).

Evaluating bids from resources with very different operating characteristics — such as solar photovoltaics, batteries and gas-fired combustion turbines — requires a shift in thinking about resource values and costs, moving toward the “net value” framework described in Strategy 1. It also requires new evaluation methods and tools that better capture the operation of solar and wind generation and their interaction with energy storage resources.

Organized wholesale electricity markets can aid utilities' bid evaluation by providing transparent public prices for a range of electricity services, including day-ahead energy, real-time energy, ancillary services, congestion management and, in some cases, resource adequacy products. The benefits of transparent pricing for evaluating diverse resources are one reason to encourage utilities to join an organized market (see Strategy 7).

Independent evaluators have become an essential feature of all-source competitive solicitations, playing a range of roles in different states. But in general, they monitor the solicitation process, ensure utility information disclosure and evaluation practices are fair and, in some cases, oversee contract negotiations. All recent all-source competitive solicitations have used an independent evaluator (Kahrl, forthcoming).

Strategy 6: Revisit the fuel cost pass-through

Give utilities more awareness of the fuel cost risks of fossil-fired generation by reforming fuel cost adjustment mechanisms

Vertically integrated utilities across the country have some form of fuel adjustment clause (FAC), which allows utilities to pass on most or all changes in fuel costs to customers without the need for a rate case. An FAC also partly insulates the utility from the risks associated with natural gas, oil and coal price volatility.[19] This, in turn, can distort utilities' resource decision-making, incentivizing utilities to underinvest in renewables and energy efficiency, which do not have fuel costs.[20]

To put this a different way, the riskiness of fuel costs should be a reason *not* to invest in a resource that requires fuel. If regulation shields the utility from the effects of such risks, however, then the utility may be inclined to take on more risk than it should, since consumers, not the utility's shareholders, will bear that risk. In many FACs, all fuel costs are automatically passed on to consumers on a monthly basis, reducing the incentive to acquire new wind and solar resources to save on fuel costs.[21]

[19] Often the FAC is combined with a mechanism to allow pass-through of power purchase and power supply expenses. These are sometimes called power cost adjustment mechanisms or energy cost adjustment clauses. To the extent that these mechanisms include fuel costs, the discussion in this section applies.

[20] For a discussion of how FACs create adverse incentives for energy efficiency, see Moskovitz (1989). Another RAP publication of the same era dubbed FACs "the anti-PBR [performance-based regulation]" (Regulatory Assistance Project, 1994).

[21] There are additional subtle ways in which a FAC can affect incentives regarding investment in wind and solar. Some states, including Hawaii, have a sub-mechanism within the FAC that rewards utilities for improving heat rates. A utility that is focused on heat rate improvements may be disinclined to ramp fossil-fired generators to support integration of variable renewable energy, given that such ramping can raise a unit's heat rate (i.e., lower its efficiency). See Littell et al. (2017).

Better alignment of incentives regarding fuel costs is achievable as follows:

- Add a mechanism to the FAC that shares the risk of fuel price changes between the utility and its customers.[22]
- Phase out the FAC by gradually reducing the amount of fuel cost risk passed on to customers each year.

Adding a Risk-Sharing Mechanism

Several states have FACs that expose utilities to some of the effects of price deviations from baseline fuel costs. Under such risk-sharing mechanisms, utilities are exposed to some of the upside of low fuel prices as well as some of the downside of high prices — and are thus incentivized to recognize some of the risk associated with fuel-consuming resources. Meanwhile, consumers are correspondingly exposed to less fuel cost risk. This approach is in contrast to a full FAC, which automatically passes on all deviations in fuel costs to consumers and thus exposes consumers to all risks associated with unexpectedly high fuel prices.

For example, in 2018, the Hawaii Public Utilities Commission modified the existing energy cost adjustment clause mechanism to include a "risk-sharing approach," specifically a "98[%]/2% risk-sharing split between ratepayers and the Company, with an annual maximum exposure cap of $2.5 million" (Hawaii Public Utilities Commission, 2018). Under this revised mechanism, 98% of any deviation from the baseline annual fuel costs the commission approves is passed to customers, up to the $2.5 million cap in any year. This gives the utility some impetus to recognize the inherent riskiness of fossil-fired generation that stems from the volatility of fuel costs. States pursuing this type of approach could consider setting the percentage lower than 98% or declining over time.

Other states including Idaho, Missouri, Montana, Oregon, Utah, Vermont, Washington and Wyoming use some version of this type of risk-sharing mechanism (Binz, 2017). In some of these cases, the mechanism includes a band (i.e., plus or minus a certain percentage) around the baseline. In this type of mechanism, the utility is able to pass on only fuel cost changes that exceed the band. New York previously had a one-sided, shared-savings fuel cost adjustment mechanism, whereby the utility would keep 20% to 40% of savings (passing the rest to customers) when fuel costs deviated below baseline (Whited et al., 2015).

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[22] Utilities can manage fuel cost risk by purchasing financial contracts that hedge fuel cost risk. Most utilities that have FACs are also allowed to pass through fuel price hedging costs (Villadsen, 2017). Any commission that seeks to adjust the FAC to limit pass-through of fuel costs should also consider limiting pass-through of any hedging costs. If the utility is exposed to fuel cost risk but is allowed to pass through unlimited hedging costs, then the utility still has little incentive to manage fuel costs.

A closely related approach is to limit the FAC on a quantity basis. This would mean setting a cap on the amount of fuel allowed in the FAC — that is, a cap on fuel use subject to allowed cost recovery. For example, the cap could be set in terms of total Btu. There could be a single cap for all fuel, or the cap could be set separately for coal, natural gas and fuel oil (Binz, 2017). In a given year, once the fuel use exceeds the allowed fuel use in the FAC, fuel cost adjustments would not be passed to consumers for the remainder of the year.

Phasing Out the FAC

Doing away with the FAC could be an option. In cases where fuel costs are a major component of expenditures (as is still the case with most utilities) abrupt elimination of the FAC may cause the utility to struggle to arrange sufficient fuel price hedging contracts or could leave the utility's financial stability subject to fuel price volatility, which may increase the utility's cost of capital.

Utilities have significant ability to manage fuel costs in the short term (by optimizing which units run at what time, improving operation and maintenance of individual units, and better managing fuel purchases and fuel price hedging) and longer term (by investing in resources with low to no fuel costs and retiring fossil-fired generation). Particularly in the short term, however, there are significant aspects of fuel cost over which the utility has limited control, namely fluctuations in the market price of fossil fuels. For regulators, the key is to provide balance between giving the utility incentive to manage fuel costs (including by acquiring wind and solar resources) on one hand and maintaining the financial stability of the utility on the other. For this reason, given that utilities still tend to have a large amount of fuel expenses, it is probably not possible to eliminate the FAC all at once.

Gradually phasing out the FAC can help balance these considerations. A phaseout could start with an existing risk-sharing mechanism and gradually reduce the amount of fuel price deviations that could be recovered from ratepayers over time. For example, the FAC could start with a particular percentage risk sharing split (as in the Hawaii example) and specify a year-by-year path for increasing the percentage of risk assigned to the utility.

Strategy 7: Think regionally

Encourage utilities to join a regional transmission organization or energy imbalance market

Promoting utility participation in regional markets can be an important strategy for making the most out of low-cost wind and solar energy. The main options are independent system operator/regional transmission organization (ISO/RTO) markets and energy imbalance markets (EIMs).

Each ISO/RTO plans, operates, dispatches and provides open-access transmission service across multiple utility territories, and each has a tariff approved by the Federal Energy Regulatory Commission (FERC) that includes rules for market and system operations. An ISO/RTO market consists of a bundle of market mechanisms and payment structures to compensate a range of services provided by generators and other resources.

ISOs/RTOs offer a number of benefits, many of which are relevant to making the most out of low-cost wind and solar generation:[23]

- ISOs/RTOs can help reduce wind and solar integration costs, allowing the utility to get more value out of wind and solar. This is because an ISO/RTO, with a geographic footprint that is broader than the service territory of a single utility, is able to smooth the variation of wind and solar generation across that territory, reducing the need for costly reserves to maintain any given level of reliability. In addition, an ISO/RTO facilitates the sharing of reserves across utilities, so that the costs to each utility are reduced.
- Each ISO/RTO has a unified tariff governing its footprint. This may alleviate inefficient "pancaking" of transmission charges and allow customers of one utility to access lower-cost resources that may be a few utilities territories away.
- Although neighboring utilities that are not part of ISOs/RTOs often trade bilaterally, the ISO/RTO markets are more efficient, as they are organized, centralized and transparent. For example, ISOs/RTOs have nodal, five-minute real-time markets with security-constrained economic dispatch, based on well-defined rules set out in the FERC-approved tariff. They also have a dedicated single system operator that manages the markets, operations and software for the regional footprint. In practice, this results in more efficient regional operations than neighboring utilities in non-ISO/RTO regions.
- ISOs/RTOs bolster price and cost transparency. This can promote discovery and development of efficient opportunities for wind and solar, including on the part of independent developers. It can also put pressure on uneconomic resources to retire.
- ISOs/RTOs have integrated regional transmission planning processes that can help identify transmission investments needed for reliability, economics and to meet policy goals.
- Because of the broad geographic scope of an ISO/RTO, encompassing many utilities often across many states, the supply of wind and solar is diversified across multiple wind areas and even multiple time zones. This enhances the value of all wind and

[23] For an in-depth discussion of the benefits associated with joining an RTO, see Pfeifenberger et al. (2016).

solar, enabling mitigation of the amount of energy that must be produced from fossil resources.

Although the net gains of joining an ISO/RTO are typically positive, there are some issues regarding distribution of costs and benefits that may dissuade some utilities from joining these organizations:

- A utility's incremental capital and operating expenses from joining the ISO/RTO may be greater than the utility would otherwise incur.
- By melding transmission costs from multiple transmission owners, an ISO/RTO may result in higher transmission costs for those utilities with below-average transmission costs. Existing members of an ISO/RTO may be resistant to utilities with high-cost transmission assets, including those built to integrate variable renewable resources, into the ISO/RTO.
- Centralized dispatch of resources results in a loss of control to which some utilities are resistant.
- Resource adequacy rules of ISOs/RTOs may conflict with state jurisdiction over electric reliability and electricity resource mixes.

These issues have led stakeholders to develop alternative creative solutions to unlock the benefits of regional markets. In recent years, a form of regional market with somewhat more limited features has emerged in the western United States. In 2014, FERC approved the California Independent System Operator (effectively an RTO) to expand the real-time market component of its services to utilities in neighboring regions, creating a structure known as the Western Energy Imbalance Market.

The Western EIM has since expanded its membership to utilities representing all or part of 14 states in the Western Interconnection.[24] A key rationale for the emergence and expansion of the Western EIM has been to lower the costs of balancing and integration of variable renewable energy, but without taking on the full structure of an RTO. In this role, the EIM has provided substantial benefits (Western Energy Imbalance Market, 2020), although less than what would be expected from a full RTO. Recognizing this, the EIM members are gradually agreeing to allow the EIM to take on some additional functions, including the possible addition of a day-ahead market. Meanwhile, other utilities have recently developed an agreement with the RTO Southwest Power Pool to develop a similar energy imbalance service in other parts of the West.[25] Utilities in the Southeast

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[24] Many of these utilities had explored forming a West-wide RTO for more than a decade but were unwilling to make that move for reasons including loss of control, expected higher costs and risk of exposure to federal regulation of portions of their business not subject to FERC.

[25] The energy imbalance service members are associations, not regulated investor-owned utilities. But the process for developing such a market would have similarities for any type of utility.

are also exploring the creation of a regional EIM or an RTO.

In virtually all cases, joining an ISO/RTO or EIM should have net benefits, although details and the level of net benefits vary. PUCs arguably have a point of leverage at the time a regulated utility considers joining an RTO or EIM. At this point, the PUC may be able to implement conditions for utility participation or request beneficial changes to market rules. The governing bodies of consumer-owned utilities have the same leverage.

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