RESOURCES FOR THE FUTURE

Does Integrated Resource Planning Effectively Integrate Demand-Side Resources?

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1. Introduction

Regulated electricity generation companies and distribution utilities in many regulated regions and organized markets in the United States use an integrated resource planning process to guide investment and procurement decisions. With varying effectiveness, this planning process integrates opportunities for demand-side management (DSM) into resource plans. In this report, we examine current planning practices to (1) evaluate the effectiveness of this aspect of the planning process, (2) identify improvements that might be implemented now, and (3) determine which practices might be essential for accommodating higher energy demand as large-scale electrification of the economy eventually occurs.

We are motivated to look at the integrated resource planning process from the demand-side perspective because we anticipate that our economy is headed toward increasing use of electricity. But for this outcome to be realized and to offer economic and environmental benefits, it must involve tighter synchronization of electricity supply and demand.

Electricity use in the economy is increasing due to innovative applications of telecommunications and electronics throughout our production and lifestyle activities. It is also being pushed in this direction by technological and market changes that have reduced the cost of electricity generation. These changes enable the electrification of energy uses that currently rely on fossil fuels for transportation and home space and water heating. For electrification to offer environmental benefits, it must involve a growing role for renewable resources. However, even as the cost of renewable resources—specifically, wind and solar photovoltaic—has fallen, making them the least-cost generation resources in many settings, their variable and diurnal availability introduces indirect costs to the electricity system as it is currently configured.

We anticipate the solution to integrating variable renewable resources involves expanded applications of demand-side resources that serendipitously become more available with electrification. In the past, most components of electricity consumption, such as home appliances, commercial lighting, or industrial processes, required high-quality and consistently available—that is, *instant on*—electricity supply. In the future, new areas of electricity consumption in transportation and buildings may differ in a fundamental way from conventional energy consumption. New electricity consumption will have the potential to be less sensitive to the variability of renewable resources or to be designed to capitalize on their intermittency. The expanding reach of electrification, such as charging a battery for a vehicle or home, and space and water conditioning in buildings, has inherent electric and thermal storage capabilities that can take advantage of low-marginal-cost generation from renewables when they are available. In other words, the demand-side attributes of electrification of transportation and buildings are

complementary to the further introduction of renewable resources. If renewables are to play a major role in large-scale electrification, the system needs to take advantage of the flexibility of new components of electricity demand.

To analyze this topic, we sample eight integrated resource plans (IRPs) to examine how well they currently represent the ability of demand-side resources to contribute to efficient, least-cost market outcomes. These plans were selected to include power regions with differing resource characteristics. We build on our observations about these plans to describe necessary changes to the planning process to anticipate a more substantial role for DSM and an associated growing renewable energy supply.

The integrated resource planning exercises we examined typically did not adequately investigate the potential of demand-side resources, leaving unrealized potential value to ratepayers, utilities, and the grid. We find that IRPs could provide better outcomes by addressing issues in the cost-effectiveness screening process, accounting for risk, and selecting a discount rate.

Moreover, the ideal IRP should describe the ability to shape load requirements to interact with supply-side resources to find the most efficient resource mix. However, most of the IRPs we sampled use a predetermined DSM portfolio (or set of portfolios) driven by either internal utility goals or external policy goals, such as energy efficiency standards. The process effectively identifies an anticipated level of demand, adjusted by predetermined levels of DSM, and focuses on supply-side resource alternatives to meet this demand. The modeling used to support the planning process needs to be strengthened to consider the interaction of demand- and supply-side resources that in the future will be of increasing importance.

This report examines how well IRPs currently accommodate the potential role for demand-side resources and identifies opportunities to improve IRPs so that they might provide guidance to achieve beneficial electrification.

2. Demand-Side Resources in Integrated Resource Plans

Demand-side management (DSM) refers to the planning, implementation, and monitoring of programs and projects undertaken by electric utilities to modify the level or pattern of electricity usage. DSM can include but is not limited to the following: demand response (DR), demand flexibility (DF), energy efficiency (EE), and conservation approaches. Table 1 offers a conceptual framework and definition for each of the DSM resource types.

Table 1. Demand-Side Management Resources

	Time-independent	Time-dependent
Proactive	**Energy efficiency**: long term or permanent customer-sited actions taken to reduce energy consumption (kWh) while providing at least the same level of services	**Demand flexibility**: use of automated systems (e.g., HVAC) in tandem with dynamic electricity prices to optimize the electricity consumption of end-use services while providing at least the same level of services
Reactive	**Conservation**: behavioral or programmatic attempts to reduce energy consumption by temporarily or continuously reducing energy services	**Demand response**: temporary actions taken to change patterns in normal customer electricity demand (kW) in response to a specific event, such as high electricity prices or threats to grid reliability

Proactive resources are practices that preempt energy use, and reactive resources are those used in response to an outside factor. For example, scheduling the charging of an electric vehicle can be proactive (a demand flexibility resource) if automated to respond to time-of-use pricing, or it could be reactive (a demand response resource) if called upon by grid operators in response to peak demand or other grid reliability concerns. Generally, we expect that efforts associated with new sources of electricity demand, including vehicle charging or preheating or cooling of space and water, would be automated (e.g., triggered by software) and therefore have a proactive characteristic.

Time-dependent resources are utilized based on the energy or system characteristics time of day or year, while time-independent resources are activated regardless of timing. For instance, once an energy efficiency measure is taken,

such as switching to efficient lighting, energy consumption is reduced regardless of timing and without being prompted by high summer prices. Therefore, energy efficiency is a time-independent and proactive approach to demand-side management. Table 2 offers examples of each type of program, taken from our sample of IRPs.

Table 2. Demand-Side Management Program Examples

DSM resource	Demand response	Energy efficiency	Demand flexibility	Conservation
Utility	Arizona Public Service	Idaho Power	Arizona Public Service	Georgia Power
Program description	**APS Peak Solutions**: offers financial incentives for commercial and industrial customers to reduce their electricity usage during summer peak periods	**Energy Efficient Lighting**: offers incentives directly to lighting manufacturers for efficient products, and savings are passed directly on to residential customers	**Load Management Technology Pilot**: deploys commercially available load control and shifting technology with a focus on understanding the benefits with respect to savings, reliability, and operation benefits; includes HVAC thermal storage and connected appliances	**Behavioral Program**: educates customers about energy use by comparing their consumption with that of similar homes to encourage good consumption practices

Sources: APS 2017b; Georgia Power 2016; Idaho Power 2017c.

Demand-side management activities are usually examined individually; however, some desirable characteristics, such as load shifting, can be activated by combining demand-side resources with time-based rates to amplify price signals for grid optimization. This integrated approach has been called demand flexibility (Dyson et al. 2015),[1] and its representation in IRPs is a key focus of this report.

The representation of DSM in IRPs was spurred by the energy crises of the 1970s and 1980s and codified into law by the Federal Energy Policy Act of 1992, which said that integrated resource plans "shall treat demand and supply resources on a consistent and integrated basis" (42 USC § 111(d)(19)). The resource planning process experienced a decline in influence during the restructuring period of the 1990s and early 2000s. Nonetheless, the planning process is currently in effect in 31 states (AEE 2018),[2] and resource plans remain a key guiding document

for utilities to respond to changes in market conditions such as fuel price and electricity demand while exploring the potential costs and benefits of different resource pathways.

We analyze eight IRPs and accompanying demand-side studies and cross-reference those findings with best practices discussed in the reviewed literature (Table 3).

The following questions are central to our analysis:

- How are demand-side resources represented in an IRP?
- Are supply-side and demand-side resources evaluated appropriately?
- Is there sufficient granularity in DSM analysis to identify the value of unique characteristics of the various types of DSM resources?
- What are key barriers facing DSM in the planning process?
- Do IRPs describe a role for DSM in facilitating the integration of variable renewable resources?
- Do IRPs describe a role for DSM in the context of expanding electrification?

Table 3. Utility IRPs Reviewed

Utility	Service territory	IRP year
Ameren Missouri	MO	2017
Arizona Public Service	AZ	2017
Dominion Energy Virginia	VA	2018
Entergy Louisiana	LA	2015
Georgia Power	GA	2016
Idaho Power	ID	2017
PacifiCorp	OR, WA, CA, WY, ID, UT	2017
Tennessee Valley Authority	TN, AL, MS, KY, GA, NC, VA	2015

Sources: See References section.

3. The Value of Demand-Side Resources

Demonstrating that a potential investment is prudent requires transparent, robust evidence that its benefits outweigh its costs. This evaluation is more important in a swiftly changing market and more challenging to satisfy when the assets in question are capital-intensive and long-lived resources—attributes that characterize, to varying degrees, supply-side resources. A concurrent evaluation of demand-side resources and how they interact with different types of generation technologies can complement this analysis.

The benefits of demand-side resources arise from both energy and nonenergy attributes, and they can accrue to the utility, customer, or society. Most of benefits are derived from the potential to offset additional energy, capacity, transmission and distribution, and fuel costs. The costs include capital, operation, and administration of the program. Some of the costs are borne by the utility and typically are passed on to the general class of ratepayers through electricity rates, and some costs can fall directly on participants in the program.

An approach to the evaluation of demand-side resources that was standardized by the California Public Utilities Commission (CPUC) in 2001 implements a cost-effectiveness screening process, which has been widely used by utilities nationally. This process is well suited to estimate ex ante the value of demand response programs that aim to shave peak demand and energy efficiency programs that lower the overall load profile. These strategies can avoid capacity and generation costs, the value of which may be relatively easy to anticipate.

However, the expanded availability of near-zero marginal cost renewable resources at various times of day has changed the diurnal profile of net demand for fossil generation. In addition, there is increasing attention to the environmental performance of the electricity system. This has brought new focus to a variety of customer, utility, and grid benefits found in demand-side resources that go beyond the measures traditionally examined in the CPUC tests. The challenge facing DSM resources is that many of these benefits are difficult to measure or are driven by novel attributes.

One novel driver of DSM value lies in demand flexibility—the ability to reshape load profiles, shifting load away from time blocks when marginal costs are high to when they are low. The opportunity to shape load profiles is likely to be significantly greater with expanded electrification of the economy and new uses of electricity. By reshaping load profiles, DSM can help mitigate renewable energy intermittency, reduce capacity requirements and the need for ancillary services, and enable the use of least-cost resources, such as daytime solar power. For example, the expansion of distributed solar has amplified the change in net load on fossil

resources associated with evening hours, when solar is not available. Demand-side resources, potentially in combination with time-varying prices, can shape demand to match the availability of low-marginal-cost generation. An example of this would be precooling of residential buildings to take advantage of solar resources midday in anticipation of the demand for air-conditioning when commuters return home in the late afternoon.

Although not the primary driver, the nonenergy benefits (NEB) of DSM resources can represent a meaningful amount of value of the resource. NEBs can accrue to the utility through avoided environmental compliance costs, reduced price volatility, and operational savings that in a market would be reflected in energy cost bids, as well as increased system reliability. Customer NEBs include positive health impacts, increased comfort, and increased home value. Some NEBs can accrue to society, such as environmental and public health benefits and resource savings (Lazar and Colburn 2013). Because of the complicated and location-specific nature of these benefits, assigning a value to NEBs is a difficult and contested task and not something that will be accounted for in markets. Nonetheless, a recent review of the past 25 years of energy efficiency (EE) NEB studies concludes that NEBs are a nontrivial component of the total program value (Freed and Felder 2017). The IRP process is one way that these values can be reflected in the operation of the electricity system.

3.1 Cost-Effectiveness Screening

In the IRP context, the evaluation of DSM programs is driven by the explicit IRP directive to use the least-cost resource, as well as by requirements imposed by policies such as Energy Efficiency Resource Standards, Renewable Portfolio Standards, state DSM plans, and other relevant state policies.[3] Utilities use cost-effectiveness screening tests to evaluate DSM programs. Generally, these programs must pass one or more cost-effectiveness screening tests to receive approval from the state regulators.[4] The California Standard Practice Manual (CPUC 2001) outlines five cost-effectiveness screening tests for demand-side programs (Table 4), various combinations of which are used almost universally (Kushler et al. 2012; Woolf et al. 2014). The National Efficiency Screening Project recently proposed a new approach to cost screening, the Resource Value Framework. This aims to guide jurisdictions in establishing the Resource Value Test as a primary test or complement to the CPUC's tests, purposely designed to reflect costs and benefits, as well as the jurisdiction's own policy goals (Woolf et al. 2017).

In cost-effectiveness screening, each state regulatory body decides which tests to use and the parameters of the screening process for its jurisdiction, which can be carried out in the IRP or separate DSM potential studies. Each test aims to evaluate the proposed program for a different purpose and from a different perspective. Each test has strengths and weaknesses; taken together, they present a detailed analysis of many of the costs and benefits of a proposed program.

Table 4. Cost-Effectiveness Screening Tests

Test	Perspective	Intended measurement	Limitation
Total resource cost (TRC)	Utility system and participating customers	Compares costs and benefits to utility and all customers	Often does not include full range of program benefits
Societal cost (SC)	Society	Compares costs and benefits to utility, all customers, and society	Difficult to estimate societal costs and benefits; full range of benefits often not included
Program administrator cost (PAC) or utility cost (UC)	Utility system	Compares avoided supply-side costs with cost of DSM program	Costs and benefits limited to those that affect the revenue requirement
Participant cost (PC)	Program-participating utility customers	Compares participant bill savings with program costs	Largely based on avoided electricity costs, not avoided system costs
Rate impact measure (RIM)	All utility customers	Compares avoided supply-side investment with program costs and lost utility revenue	A measure of distributional equity, not cost-effectiveness

Sources: CPUC 2001; Woolf et al. 2017.

The TRC test was the most commonly used, present in six out of eight plans in our sample, often in combination with other tests. Georgia tried to strike a balance between the economic efficiency described by the TRC and distributional equity described by the Rate Impact Measure (RIM) test (Georgia Power 2016, p. 5-65). Dominion Energy Virginia evaluated resources on an individual and a portfolio basis. Resource options in Dominion's analysis cannot be rejected based on the results of just one test according to Virginia code, whereas many other states rely on the results of their selected primary test as the ultimate pass-fail criteria. Therefore, the company considered only those resources that pass all three of the TRC, UC, and PC tests (the RIM test is also considered if it is low enough to offset high scores on the three tests) (Dominion 2018, 93). In Entergy Louisiana's long-term demand side potential study, ICF International (2014, 9) calculated the TRC test three

times (2014, 2020, 2022). Short-term capacity surplus in the MISO power market was forecasted to stabilize in 2022, but suppressed the short term avoided costs of efficiency; consequently, ICF decided to use 2022 as the base year for cost-screening.

Arizona is the only state sampled that uses the Social Cost (SC) test as its determinative test, although the major utility, Arizona Public Service, pushed heavily for the inclusion of the RIM test (APS 2017b, 67). The Tennessee Valley Authority did not use any of the five tests and instead used its own cost-benefit analysis (TVA 2015a, 124). These findings for the sample of IRPs we examined align with findings from a 2012 survey from the American Council for an Energy-Efficient Economy (ACEEE) that found that most states use more than one test, but 71 percent of states used the TRC as their primary cost-effectiveness screening test (Kushler et al. 2012). This variation shows how the tests can be used in different ways to reflect the viewpoint of the governing body.

Relying on the TRC as a single determinative test is problematic because it provides an incomplete perspective on the proposed program. The TRC test aims to represent the costs and benefits to the utility system and both participating and nonparticipating utility customers. It does this by comparing costs in the form of new infrastructure and program investments against utility and customer benefits, the components of which can vary by utility. The benefits of the DSM programs calculated in the TRC can vary by jurisdiction but are defined in the CPUC manual as "the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction" (CPUC 2001, 18). This definition of benefits leaves out crucial aspects of demand-side resource value such as nonenergy benefits and activating the flexibility of demand generally to benefit customers, the utility, and the grid system itself, thus producing a skewed test that evaluates all a program's costs against only some of its benefits.

On the system scale, the value of load-shifting and grid flexibility is seldom observed in cost-effectiveness screening. However, investing in demand-side resources offers the ability to reduce ramp-up and curtailment rates, shorten or reduce peak demand windows, and stabilize prices. These characteristics are not captured in avoided capacity cost estimates that focus on only the megawatts (MWs) of deliverable electricity.

The Rocky Mountain Institute recently modeled the economic potential of demand flexibility, as defined in Table 1, in the residential sector of Texas (in ERCOT's territory, representing 85 percent of Texas's electric load) based on hourly net wholesale clearing prices and a suite of grid-connected demand-side technologies in a high-renewable future scenario (Goldberg et al. 2018). The modeling identified $1.5 billion per year annualized generation and transmission savings and the $400 million in avoided fuel costs per year associated with demand flexibility in Texas.

Traditional cost-effectiveness screening might be expected to account for some of this value; however, the standard screening tests will likely not account for the value of reducing the steep change in net load on fossil resources. The authors found that demand flexibility could reduce the curtailment of renewable resources by 56 percent in the early evening hours and by 40 percent on an annual basis in Texas. This effect benefits both the utility and customers by providing the most efficient resource available to match demand and supply. Further economic value would be found through avoided line loss, reduced ancillary service requirements, and system resilience, which were not assessed in the model. However, achieving such savings would require a substantial investment in demand-side resources and change in both utility and customer practices—a change that requires significant forethought and planning to achieve. This is why the value of grid flexibility offered by demand-side resources needs to be properly represented in integrated resource planning, which is the utility's outlet for exploring how to meet future demand with least-cost resources.

Four of the eight utilities in our sample of IRPs acknowledged that flexible demand side resources would be an important aspect of the future resource mix. This is generally expressed in the IRPs through technology potential studies, forward-looking pilots, and in rare cases, concrete programs such as Arizona Public Service's Residential Demand Response, Energy Storage and Load Management Program (2017b, 67). Idaho Power, a utility relying heavily on hydro power, used historical data to identify which months will have the greatest need for flexibility in the future (2017b, 127). One utility included a quantitative factor that captured some of the value of flexible resources when determining cost-effectiveness. Ameren Missouri used the recommendations found in Woolf et al. (2013) to guide its valuation process for demand response and included this benefit in its calculation of avoided energy costs. When discussing load-shifting practices, its DSM study states, "This shift in the timing of energy use can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate" (GDS Associates 2016, 109). This provides a good example of first steps to formalize the value of flexible resources in the planning process.

The nonenergy benefits of DSM programs can account for a tangible portion of the program's value and merit inclusion in cost-effectiveness screening, but they are seldom applied historically or in our sample of IRPs. State public utility commissions (PUCs) can require utilities to include NEBs in their screening; however, the definition and scope of the NEBs included are often either limited or opaque. According to Kushler et al. (2012), of the 36 states conducting an evaluation of demand-side programs that includes a measure of participant costs, only 12 also included a participant nonenergy benefit measure in their calculations. Five of these states did not specify their NEB categories, but 7 did. However, in these 7 states, most or all of these benefits were limited to avoided water and fuel savings. Two states also specified operation and management savings, one used a general adder, one listed as an "other" category of benefits, and none evaluated health, comfort, or productivity improvements.

This means, for example, that if a utility customer installed a smart thermostat as part of a DSM program, the part of the installation cost borne up front by the customer will be included in the screening test. Yet the benefits to the customer (e.g., bill savings, comfort, health benefits), which may be the very reason that individual chose to participate in the DSM program, are frequently not included in the analysis. If a program's full costs are included in the evaluation but not the full extent of the benefits, the analysis is biased.

The representation of nonenergy benefits in our sample of IRPs was sparse. Five of the eight IRPs examined did not include any nonenergy benefits in their cost-effectiveness screening. PacifiCorp includes NEBs in calculations for only two of its five service states, and there is no information available as to what was included in the NEBs (AEG 2017a, 2-9). Arizona Public Service (APS) uses the SC test, which should include utility, customer, and societal NEB's in its calculation, yet APS did not offer a breakdown of how it came to its societal benefits estimates (2017b, 176). TVA calculates air, water, and waste impacts in a robust environmental impact statement used to screen portfolios in a qualitative manner, but these impacts did not have any quantitative effect on the value of individual resources when forming these portfolios (TVA 2015b). Idaho Power includes NEBs in its TRC calculations, at the sector level, not the resource level (Idaho Power 2017c, 61). A significant amount of complexity is lost in this step, as programs in the same sector but with different NEB characteristics, such as residential efficient lighting and refrigerator and freezer recycling programs, will be generalized to have the same NEBs. While some analyses try to include NEBs, the exact parameters of what that includes is difficult to discern, and to our knowledge,[5] no utility included customer impacts such as increased productivity or health.

Specifying the scope, application, and quantification of nonenergy benefits may be a controversial subject. They are, however, an integral aspect of the value of demand-side resources that is largely not acknowledged by current practices. State PUCs should include NEBs in cost screening and clarify the definition and scope of NEBs for their jurisdictions according to relevant policy goals.

3.2 Representing Investment Costs when Comparing Alternative Resources

Representations of risk and the cost of capital are two key factors in investment analysis. The way these factors are represented in the IRP process seemingly conveys an important disadvantage to the evaluation of demand-side resources.

The risk associated with an investment reflects the likelihood that the estimated full net lifetime cost of the resource will materialize at the predicted rate. The cost described is net of changes in the costs of other resources. For example, if the price of renewables were to fall, the cost of investment in a natural gas facility would be higher because it would be likely to run for fewer hours each year than initially

anticipated. The converse is also true; falling fuel prices might lead a new gas plant to run more hours and reduce its cost. Therefore, uncertainty is a primary driver of the cost of investing in generation resources. In an option value framework, more variation in possible outcomes, even if expected outcome is unchanged, raises the cost of investment.

Supply-side resources are exposed to considerable amounts of difficult-to-avoid risk linked to construction costs, long lead times, fuel price volatility, supply chain vulnerabilities, and evolving environmental regulations. In contrast, demand-side resources generally have lower risk because of their nature as small, scalable, and diverse investments with short lead times (Lazar and Colburn 2013). The risk of demand-side resources is based on program adoption rates, program measure performance, ex post delivery of forecast savings,[6] and unanticipated costs. However, as some DSM programs are iterative, these risks may be mitigated as program design improves with time. Additionally, demand-side resources reduce the overall risk of the utility's resource portfolio by diversifying its assets, making its portfolio less sensitive to fluctuating fuel prices.

In evaluating all resources, the IRP should explicitly describe and quantify the risk factor associated with each technology, recognizing that it varies across technologies. It is noteworthy that there is a risk associated with the operation of existing investments, because of factors such as fuel price uncertainty. Consequently, that risk should be reflected as an additional cost to the expected value of the operation of existing resources with the IRP evaluation, in a manner comparable to the consideration of risk associated with investments.

A second factor that differentiates the cost of investment for supply- and demand-side resources is the cost of capital. The cost of capital for supply-side investments for investor-owned utilities (IOUs) reflects the general risk profile and capital structure for the company, which reflects the weighted average of the utility's debt burden and equity. Investments by independent power producers typically involve project-specific financing, but investments by IOUs, which are the firms most likely involved in an IRP process, are more likely to be corporate financed. Historically, this weighted average cost of capital (WACC) has been used to evaluate the cost of both supply- and demand-side resources and was viewed as a way to compare both types of resources evenly.

Demand-side resources are structurally different investments from supply-side resources (Lazar and Colburn 2013; Woolf et al. 2014, 2017). As we have noted, there are performance risks associated with demand-side investments just as with supply-side investments, and the value of demand-side investments is affected by changing fuel prices just as is the value of supply-side investments. However, the cost recovery for a demand-side investment is nearly risk free, which should be reflected in the risk premium and hurdle rate associated with the investment, but also because ratepayers, rather than the capital market, are the source of capital.

Ratepayer-funded DSM programs are common, found in at least 44 states and the District of Columbia (Kushler et al. 2012). How and the degree to which costs are passed to ratepayers can vary by state. Of the 16 states covered by the utilities in our sample, 15 allowed program administration costs to be recovered from ratepayers (IEI 2014),[7] 12 also had ratepayer-funded fixed-cost recovery mechanisms that are intended to remove the utility's disincentive to reduce its sales through EE,[8] and 9 had additional performance-based incentives for DSM programs that allow the utility to earn a rate of return successful DSM programs,[9] similarly to supply-side resources (Cooper 2017; IEI 2014). However, because in each case program costs for demand-side programs are recovered through short-run adjustments to the consumer bill, the recovery of program costs is very low risk to the utility, and consequently a lower discount rate may be called for in program evaluation.

In IRPs, the risk and cost of capital for investments are summarized in the choice of the discount rate used in calculating the levelized cost of energy.[10] Typically, a single discount rate is used to evaluate the costs of both demand- and supply-side resources. This practice is problematic because supply-side resources differ from demand-side resources with respect to both considerations. A higher discount rate implies that greater payments—that is, a higher levelized cost of energy ($/MWh)—are required to recover the initial cost of the investment. Consequently, the use of the same discount rate for supply- and demand-side investments conveys a relative disadvantage to demand-side investments because they have lower risk and a lower cost of capital.

Discount rates used in IRPs are set by the state's regulatory body. It would be possible to apply different discount rates to different aspects of an IRP. For instance, supply-side resources could be evaluated using the WACC because they are based on the utility's cost of capital, while demand-side resources could use another discount rate. Ultimately, the discount rate reflects the time preferences of the party affected by the investment and the broader policy goals that shape the investment. When different tests are applied to evaluate DSM investments, different criteria are explicitly in play. For example, the social cost test implies a social perspective, which in turn suggests that options should be evaluated with the social discount rate, which will be lower than the WACC. Considering the significant impact that a discount rate can have on the outcome of cost-benefit analyses, these structural differences between supply- and demand-side investments merit careful consideration when choosing discount rates for cost-effectiveness screening.

Five of the eight IRPs examined use the utility's WACC as the discount rate. Three did not disclose the rationale for their selected discount rates (Table 5). Georgia Power is the only utility sampled that did not disclose its selected rate, which strains the ability of the state commission and stakeholder groups to evaluate the utility's analysis. Dominion does acknowledge that the appropriate discount rate to use should be from the viewpoint of the collective customers:

> In principle, the appropriate discount rate to evaluate alternative expansion plans is from the standpoint of utility customers collectively, not the utility. While the customer discount rate is unobservable, it is a function of the opportunity costs facing utility consumers. This rate would be the same regardless of the expansion plan being evaluated. Absent knowledge of the customer discount rate, it is not unreasonable to use the utility discount rate [WACC] as a proxy (2018, 115).

Regardless, Dominion does not attempt to calculate a customer-based discount rate or use a proxy and instead relies on the WACC, which is not indicative of collective customers' interests. Idaho Power agrees that the WACC is not suitable to use for participant benefits and uses an adjusted WACC in the PCT and RIM test as a proxy for the difficulty of measuring customer discount rate (Idaho Power 2017a, 4). However, this practice does not extend to Idaho's primary tests, the TRC and UCT, which rely on the WACC. Most notably, APS, which is directed to use the Societal Cost Test by the state's regulatory body, used the highest-known WACC-based discount rates of our sample, which clearly does not represent society's perspective that the test aims to take (APS 2017b, 212).

Table 5. Discount Rates Used in IRP Sample

Entity	Ameren	APS	Dominion	Entergy Louisiana	Georgia Power	Idaho Power	PacifiCorp	TVA
Source	WACC	WACC	WACC	Does not state	—	WACC	WACC	Does not state
Rate	5.95%	7.50%	6.31%	7.66%	Does not disclose	6.77%	6.57%	8%

Risk analysis performed at the portfolio level offers insight into the resilience of the portfolio; however, it does not identify an ideal mix of resources with complementary risk profiles. An evaluation of the correlation of risk factors among resources in the portfolio requires analysis of the resources collectively as well as individually. This approach may identify a combination of traditional, renewable, and demand-side resources that has a low level of risk correlation that may not be identified by evaluating risk solely at the portfolio level.

Three of the four utilities that use stochastic analysis to evaluate risk profiles did so at the portfolio level. In contrast, TVA demonstrates that stochastic risk analysis at the resource level is possible by evaluating the risk of EE resources, which it then includes in its resources analysis as a cost factor. TVA declares that "even

after accounting for the planning factor uncertainty, EE blocks have a significantly lower range of uncertainty than a comparable combined cycle plant" (2015a, 155). Although this detailed analysis is informative, TVA did not evaluate supply-side resource risk with a congruent stochastic analysis. The $/kW installed capital costs metric used by TVA in its modeling then includes an explicit risk cost for EE resources but not supply-side resources, which then yields resource mixes based on uneven analysis.

In another approach to risk analysis, Dominion Energy (2018, 116) analyzes a risk-free 0 percent discount rate for two of its four possible scenarios. Since the risk-free analysis is done at the portfolio level, the 0 percent discount rate is applied to a portfolio predetermined by Dominion's cost-benefit analysis. The capital, operations and maintenance, fuel, and other costs of all the resources included in each portfolio are aggregated, and then the risk-free discount rate is applied. This approach misses an accounting of the risk associated with any one resource, which could be valuable to the construction of an overall resource plan.

4. Meeting Future Demand with Resource-Neutral Competition

The best practice in resource planning evaluates demand- and supply-side resources on comparable terms. Once DSM programs have been properly screened for their cost of capital and risk characteristics in a distinct manner that nonetheless is parallel to what is done for supply-side resources, a levelized cost of energy for DSM programs can been produced. The next step is to compare demand-side resources with supply-side resources to find the least-cost mix of resources to meet forecast demand under varying assumptions and policy-based scenarios. Most utilities select a preferred or base plan to use as a reference point against which to evaluate other plans. Some utilities rank the plans based on a utility-specific set of metrics including the utility's goals and financial, economic, and environmental impacts.

In principle, this process should present a robust representation of the most efficient resource plans, accounting for the different qualities of each available resource type. However, even if the DSM valuation issues previously discussed are addressed, there can still be significant barriers to participation of cost-effective demand-side resources.

The key to full representation of demand-side resources is to model them as a competitive resource along with supply-side resources to fulfil forecast demand. However, this is rarely done in practice. Most utilities determine ex ante a level of demand-side investments through an outside planning process that they engage in, driven by either policy mandates or an administrative decision based on the cost-effectiveness screening tests (Kahrl et al. 2016; Lamont and Gerhard 2013; Satchwell and Hledik 2014). The predetermined level of demand-side investment appropriate for each scenario is directly applied within the planning process to reduce the forecast demand. The remaining adjusted level of demand is met by supply-side resources. In IRPs that practice this method, the amount of demand-side resources called for will not vary in response to changes in the scenario inputs, such as fuel prices or environmental compliance costs. This practice of treating DSM as a static input to resource modeling cannot accommodate the dynamic, changing nature of our electricity industry and the value of flexible demand-side resources in response to those changes.

Six out of the eight reviewed IRPs did not model DSM as a competitive resource. Some utilities clearly expressed the fact that demand-side resources are input as a forecast load reduction before any supply-side resource modeling (Entergy 2015, p. 30; Georgia Power 2016, p. 5-60); for instance, Idaho Power states, "No supply-side generation resource is considered as part of Idaho Power's plan until all future cost-effective, achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads" (Idaho Power 2017b, 47).

Other IRPs' methods are not as transparent and require some examination to make clear that this method was used (Ameren Missouri 2017, Ch 9 p. 10; APS 2017b, 117). The scale at which demand-side resources are used as an input to the resource model can be either at the totality of potential DSM programs (four of the eight IRPs) or broken into DSM portfolios applied to each scenario (two of the eight IRPs), as seen in Ameren and APS's IRPs. Ameren analyzed EE and DR programs separately at both their maximum achievable potential and realistic achievable potential to find the lowest-cost option among a series of scenarios (Ameren Missouri 2017, Chpt 9: 10). APS created two portfolios, a base and expanded DSM, to use where appropriate in its proposed scenarios (APS 2017b, 119).

Defenders of this approach of using DSM to modify load forecasts might point out that locking demand-side investments into the resource plan ensures their contribution to the resource mix and is taken into account in the determination of need for generation resources. Failing to account for DSM would lead to erroneous forecasts of the need for new generation. For instance, Dominion Energy Virginia's 2018 IRP was recently rejected by the Virginia State Corporate Commission (SCC) on the grounds that the company did not take into account the load impacts of state mandated efficiency and storage investments. Adjusting load forecasts based on fixed DSM expenditures would yield a more efficient resource mix than the alternative of not modeling the impact of DSM (SCC, 2018). Nonetheless, this method does not allow for the level of investment in demand-side resources to vary according to changes in other inputs such as fuel price, environmental compliance costs, or economic trends, which could likely lead to an inefficient level of DSM investments. If a minimum level is mandated by policy, locking in demand-side investments at this level will preclude the ability for greater contribution in scenarios where supply-side resources are less available.

Our selected group of IRPs is small and not a random sample, so it cannot accurately represent the proportion of utilities that fix the amount of demand-side investments in the resource plan modeling. To investigate this further, we aggregate our findings with the results from Kharl et al. (2016), Lamont and Gerhard (2013), and Satchwell and Hledik (2014) to build an expanded sample of 35 unique utility IRPs examined over the years 2010–18.[11] In this expanded sample, 33 of these IRPs treat DSM as an input into the modeling.

On the other hand, PacifiCorp and TVA allowed supply- and demand-side resources to compete for every kWh of forecast demand. To do this, they compiled estimates of the levelized cost of each supply- and demand-side resource at various levels of availability, grouped these measures by shared characteristics for modeling purposes, and created individual cost curves for each group of resources.[12] Both utilities input the resource cost curves into a model called System Optimizer, which minimizes the present value of the revenue requirements for the modeled period (PacifiCorp 2017, 143; TVAa 2015, 63). This approach intends to allow DSM to bid competitively with supply-side resources to find the least-cost mix of resources

and is best practice (Wilson and Biewald 2013). However, limitations can still suppress DSM, such as misguided cost screening, restraints on the growth rate of EE resources,[13] or creation of an artificial ceiling for capacity and energy savings.[14] These may reflect real-world limitations or the bias of the model user.

Finally, even where demand- and supply-side resources compete for every kWh of energy service provided, there are limitations that pose a challenge to the realization of potential demand-side resources and their possible role in the integration of renewables. Modeling of these resources is more complicated when dynamic issues regarding storage are introduced, but this is nonetheless likely to be increasingly relevant with expanded electrification of the economy. The System Optimizer can be used to accommodate grid-level storage such as pumped hydro or batteries and potentially thermal storage for water and space conditioning. However, the model is less likely to be used in this way because it is computationally more difficult and expensive. Moreover, the representation of the demand side lacks information about cross-time elasticities of substitution that influence the ability to shift demand across time blocks. Hence, even best practice is unlikely to capture the value of demand flexibility, and important opportunities exist for improving the practice of integrated resource planning.

Conclusion

Integrated resource planning continues to play an important role in shaping the power industry. We review eight recent IRPs to determine the extent to which standard industry planning practices account for the potential expanding contribution of demand-side resources to enable further electrification of the economy and simultaneously further integration of variable energy renewables. The findings from our survey of recent IRPs highlight several opportunities to improve the resource planning process.

First, the cost-effectiveness screening practice needs to be rethought. The nearly two-decade-old standard tests were created during a time when the needs of the power system and society were different. These five tests provide a framework for evaluating specified demand-side investments, measured, for example, against the avoided cost of new generation, but they cannot account for their system-level value as a complement to renewable resources. While the five tests remain useful, they are not sufficient given the growing complexity of the grid.

Second, the differences in the cost of capital for demand- and supply-side resources should be acknowledged when considering the discount rate. Demand-side programs are funded using ratepayers' capital, which makes them nearly risk free to the utility, whereas the utility must go to the capital market to fund supply-side investments. Using the utility's weighted average cost of capital to discount demand-side resources ignores this key distinction and potentially yields misleading results.

Third, the planning process should carefully distinguish the risk profiles of individual demand- and supply-side resources. Uncertainties such as fuel prices and environmental regulations will vary depending on the features of different resource types. While continuing to evaluate plans at the portfolio level is crucial, additional information is needed to inform the construction of the portfolio. Increasing the granularity of risk assessments will reveal information on how various resource mixes could mitigate key risk factors and allow for planners to identify the least-cost, least-risk mix of resources.

Fourth, novel market trends and emerging technologies such as demand flexibility can shift consumption across time periods in response to or in anticipation of the availability of generation resources. This possibility will expand with the expansion of electricity to new uses. To contend with these changes, a new degree of resource modeling is needed. The two current options, cost-effectiveness screening of predetermined DSM portfolios and resource-neutral competition, remain valuable, but they cannot capture the complexities inherent in an increasingly electrified economy with large-scale renewable and DSM deployment. New tools are needed in resource planning that can account for the strategic complementarity of flexible demand and variable supply.

This report has focused on the planning process of utilities from the perspective of the regulated market; however, wholesale markets face similar challenges posed by economy-wide electrification. The Federal Energy Regulatory Commission (FERC) has a history of supporting the role of demand-side resources in wholesale markets. FERC Orders 890 and 1000 brought nonwires alternatives, which include many of the DSM resources mentioned in this brief, into the regional transmission planning process. Orders 719, 745, and 841, as well as a 2017 Declaratory Order,[15] aim to protect the rights of owners of DSM resources to bid into the market and to remove key barriers to their participation. While some of these decisions have been controversial, most notably Order 745, FERC has consistently supported a resource-neutral, market-based approach to wholesale market regulation.

Solutions to the challenges facing the electricity industry are much more nuanced than simply allowing demand resources to bid into the market or adjusting IRP practices. How should rates be designed to safeguard ratepayer fairness and ensure utility solvency? Who should own the distributed grid resources of the future? Where should the value added of these resources accrue? How can novel attributes such as demand flexibility be properly internalized by planners to ensure appropriate deployment of resilient resources? Addressing these issues will be key to unlocking the full deployment of renewables on a pathway to an electrified, low-carbon future.

Notes

1 DF is very similar to integrated demand-side management (IDSM), "defined as the integration/coordination of the delivery for three or more of: (1) energy efficiency (EE), (2) demand response (DR), (3) distributed generation (DG), (4) storage, (5) electric vehicle (EV) technologies, and 6) time-based rate programs to residential and commercial electric utility customers" (Potter et al. 2018, vii). The key difference is that DF assumes the use of time-based rates in tandem with other DSM resources, whereas time of use (TOU) rates are one option in IDSM.

2 Wilson and Biewald (2013) identify integrated resource planning activities in 28 states. We count 31, drawing on information from Advanced Energy Economy's Powersuite database.

3 An example of a relevant state policy is Virginia's Grid Transformation and Security Act of 2018, which calls for at least $870 million in DSM program proposals for the 2018–28 period (Dominion Energy Virginia 2018, 44).

4 An inherent issue with any ex ante cost-effectiveness screening test is the unanswered question of whether the test results are an accurate indicator of ex post savings. This uncertainty contributes to the risk of DSM resources, discussed in the following section.

5 Definitions of NEBs often included "other quantifiable impacts." Customer impacts could be included in this term; however, no IRP reviewed discussed what was included in this measure.

6 The energy savings used in cost-effectiveness screening are based on ex ante estimates derived from modeling results and are subject to uncertainty. There is debate as to how accurately DSM measures achieve forecast savings. Some studies show that ex ante forecasts of savings are generally achieved but with wide variation in outcomes, while others show costs exceed savings. The outcomes of ex post analysis could have significant implications for the threshold of cost-effectiveness accepted by planners. See Gillingham et al. (2018) for a recent review.

7 Administration costs are recovered through rate cases, system benefits charge, or tariff riders (IEI 2014).

8 Since some rate designs tie the recovery of fixed costs to volumetric electricity sales, utilities are disincentivized to invest in EE and other DSM programs that reduce total sales. Fixed-cost recovery mechanisms such as rate decoupling and lost revenue adjustment mechanisms aim to mitigate this by allowing the utility to recover the marginal revenue of fixed costs (IEI 2014).

9 For example, Georgia Power can earn an 8.5 percent return on EE programs if they achieve 50 percent or more of projected savings (Cooper 2017).

10 Discount rates reflect the time value of money; they represent the relative importance of short-term costs and benefits versus long-term costs and benefits. High discount rates place a greater emphasis on the short term, while low discount rates emphasize the long term.

11 Lamont and Gerhard (2013) specifically examine energy efficiency in IRPs, and Satchwell and Hledik (2014) examine demand response; however, we feel it is appropriate to aggregate these individual resource types into a broader definition of DSM, as there is generally little variation in how they are treated in IRPs. Several utilities' IRPs were examined in more than one study. Notably, PacifiCorp appeared in all four studies. Where there are duplicate analyses, the findings from the most recent IRP are used to reflect evolving IRP practices.

12 For example, PacifiCorp reduced 33,000 EE measure permutations into 27 bundles across seven states, leading to 187 supply curves; TVA split EE measures into market segments, then tiers, and then blocks, yielding a total of 44 EE resource blocks.

13 TVA limited the growth of EE to 25 percent annual growth in years 1 to 5, 20 percent for years 6–15, and 15 percent thereafter (Takahashi et al. 2015; TVA 2015a, 148).

14 By limiting the capacity (MW) and energy (GWh) of each energy efficiency resource tier and block, EE is restrained from bidding into the model beyond a certain point (Takahashi et al. 2015; TVA 2015a, 148).

15 **https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14769684.**

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