Survey of Western U.S. Electric Utility Resource Plans

Wilkerson, Jordan

2014-01-06

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LBNL-XXXX

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Environmental Energy Technologies Division

January 2014

The work described in this report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

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Prepared for the
U.S. Department of Energy
National Electricity Delivery Division
Office of Electricity (OE) Delivery and Energy Reliability

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January 2014

Pre-print of article accepted for publication by Energy Policy

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Acknowledgements

The work described in this report was funded by the National Electricity Delivery Division of the U.S. Department of Energy's Office of Electricity (OE) Delivery and Energy Reliability under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. The authors would like to acknowledge Larry Mansueti (U.S. Department of Energy-OE) for supporting this project.

We thank Charles Goldman and Joe Eto at LBNL for providing constructive comments on an earlier version of this draft. We thank Joel Swisher of Stanford University for his helpful suggestions. Doug Larson, Thomas Carr, Steve Ellenbecker, and Alaine Ginocchio of the Western Interstate Energy Board provided initial guidance on the scope of this research project. We also thank the participants of the 2012 Joint Meeting of the Resource Planners Forum, CREPC, and SPSC for their feedback on our preliminary research findings. Jordan Wilkerson was supported by a subcontract with Lawrence Berkeley National Laboratory and a Stanford Management Science & Engineering Graduate Fellowship. Any remaining omissions and errors are the responsibility of the authors.

Abstract

We review long-term electric utility plans representing ~90% of generation within the Western United States and Canadian provinces. We address: what utility planners assume about future growth of electricity demand and supply; what types of risk they consider in their long-term resource planning; and the consistency in which they report resource planning-related data. The region is anticipated to grow by 2% annually through 2020—before Demand Side Management. About two-thirds of the utilities that provided an annual energy forecast also reported energy efficiency savings projections; in aggregate, they anticipate an average 6.4% reduction in energy and 8.6% reduction in peak demand by 2020. New natural gas-fired and renewable generation will replace retiring coal plants. Although some utilities anticipate new coal-fired plants, most are planning for steady growth in renewable generation over the next two decades. Most planned solar capacity will come online before 2020, with most wind expansion after 2020. Fuel mix is expected to remain ~55% of total generation. Planners consider a wide range of risks but focus on future demand, fuel prices, and the possibility of GHG regulations. Data collection and reporting inconsistencies within and across electric utility resource plans lead to recommendations on policies to address this issue.

Keywords: Resource Planning, Electric Utility, Risk and Uncertainty

1. Introduction

Electric utility resource planners' decisions affect *all* residential, commercial, and industrial customers. Planners must decide how to meet future demand with limited information about future fuel prices, economic conditions, technology advancements, and governing policies. Assessing the risk of not meeting demand is essential to the planning process. Not surprisingly, load serving entities[1] (LSEs) typically develop their plans for meeting future demand over the course of several years. The long-term planning process involves many stakeholders and can be computationally intensive. Many utilities are required to publicly-release and defend their integrated resource plans (IRPs) in front of consumer advocates, Public Utility Commissions (PUCs), and other stakeholders.

This study is a broad comparison of resource planning content and an aggregation of the collective forecasts of LSEs operating within the Western Electricity Coordinating Council (WECC) region. We review publicly-available planning information for nearly 40 utilities that, in aggregate, generate ~90% of the electricity in WECC. Since many of the resource plans are more than a year old, we also sent a supplemental survey to resource planning staff to give each an opportunity to update their load and resource projections. Most responded with updated information, including a few for which we could not locate plans. The results presented in the following sections are based on the best available information from LSEs as of August 2012. We conducted this analysis in order to gain insight into the following questions: (1) What are Western electric utility planners assuming about the future growth of electricity demand and mix of supply- and demand-side resources? (2) What types of risk do Western electric utilities consider and address in their long-term resource planning? (3) How does the collection and reporting of resource planning-related data differ across this region?

We report aggregate future demand and power plant fuel mix trends, identify the uncertainties LSEs focus on as they develop their IRPs, and report on emerging trends considered by planners. Reporting differences are a reflection of differing state reporting requirements, and these inconsistencies affect our ability to compare some planning assumptions. Accordingly, the availability and consistency of planning information is a focus of this analysis.

This paper is organized as follows. Section 2 provides a brief review of previous IRP surveys. Section 3 describes important steps in the planning process. Section 4 describes the data and methods we use to compare IRPs. In Sections 5–7, we compare planning assumptions as we address the questions above. We conclude with suggestions that could improve inter-comparison and ultimately lead to more efficient long-term regional planning.

[1] Some entities covered in this study are not technically LSEs, but we refer to them collectively as LSEs for simplicity. They include investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; and power marketers.

2. Past utility resource planning surveys

2.1 Brief history of resource planning

Early advocates for integrated resource, or least-cost planning, emphasized the value of improvements in demand-side efficiency. Both the public and private sector actively searched for cost-effective ways to get more services with less energy (Cavanagh, 1991). The IRP process offered advantages over traditional resource planning, because it included demand side management (DSM) as a resource (e.g., Hill et al., 1992; Sioshansi, 1992; Swisher and Orans, 1995; Vollans, 1994). Successful planning in this manner ensured the reliable production and delivery of energy at the lowest practical cost. Early research defined what an IRP is (e.g., Hirst and Goldman, 1991; King, 1992; Lenssen, 1996), what an IRP should include (e.g., Hirst, 1994; Kahn, 1992), and what types of software tools were available to conduct long-term planning (e.g., Eto, 1990; Hoog and Hobbs, 1993; Rosekrans et al., 1998).

The Federal Energy Policy Act (1992) formally defined the term *Integrated Resource Planning* for the U.S. Federal Government and required utilities that purchased electricity from federal power authorities (e.g., Western Area Power Administration) to create an IRP. The Energy Policy Act provides some basic guidelines, but rules and requirements governing long-term electric utility planning activities are mandated by state or local governments and agencies. State-level planning requirements are carried out through legislation, codes, agency requirements, or PUCs who adopt IRP regulations. Today, there are 28 states with formal IRP filing requirements, and 11 other states that have adopted the Long-Term Procurement Plan[2] (LTPP) framework as an alternative to IRP. (Wilson and Peterson, 2011).

All of the states with utilities that are members of WECC currently have a formal IRP reporting process, except for California which has an LTPP process. LSEs refer to their plans using a variety of names including: IRP, LTPP, Electric Resource Plan (ERP), Expansion Plan (EP), Long-term Transmission Plan (LTP), Resource Procurement Plan (RPP), and Transmission Assessment Plan (TAP). Although each title means something slightly different to each planning department, all effectively accomplish similar tasks. For convenience, we will refer to all of these activities as IRPs throughout this paper. Although many general IRP requirements are similar, the rules governing IRP content are generally defined by the PUCs, so there are significant differences between planning objectives, analysis horizon, and reporting frequency. One consistent theme across all jurisdictions is the requirement to consider all feasible supply-side and demand-side resources.

2.2 Infrequent evaluations of resource planning

The first evaluations and comparative analyses of IRPs occurred before the Energy Policy Act provided resource planning guidelines and definitions. Hirst et al. (1989) evaluated a specific utility's IRP−Puget Sound Power & Light. Hirst (1989) then reported on the internal activities of the same utility as they established an improved planning process. Hirst and Goldman (1991) evaluated regulatory incentives for ~20 PUCs and the utilities under their jurisdiction, outlining key components of a successful IRP process.

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[2] LTPPs include much of the same information as an IRP, but typically have shorter planning horizons.

However, many early surveys covered specific aspects of resource planning (e.g., DSM) (e.g., Berry, 1993; Esteves, 1989; Goldman and Kito, 1995; Wiel, 1991). Schweitzer et al. (1991) surveyed 24 LSEs for current and future peak power and energy demand, electricity generation, and DSM savings, noting that DSM strategies were underutilized in the past, but utilities had aggressive DSM forecasts. Eto (1990) reviewed modeling software used by resource planners at a few specific utilities. Twenty years later, Foley et al. (2010) discussed modeling approaches and described proprietary software used by the electric industry. Consultants at Aspen and E3 (Aspen/E3, 2008) summarized assumptions, models, and other information used by utilities in their planning, and provided information about regulatory requirements, procurement processes, and planning practices for 16 utilities.

One issue that continues to surface is reporting inconsistencies across LSEs. Hirst (1994) compared ~50 plans and provided guidance on how to conduct planning, but found that there were significant data inconsistencies between plans. Bolinger and Wiser (2005), highlighted the importance of the IRP process as driver of renewable energy but noted plans varied widely in availability and completeness of data which limited the evaluation. Hopper et al. (2006) found that some Western utilities planned to meet a significant fraction of incremental resource needs through energy efficiency, but also identified significant opportunities to improve the treatment of efficiency in resource plans noting inconsistencies in reporting methods and detail. Barbose et al. (2008) evaluated Western utility resource plans to assess how utilities assess carbon regulatory risk within their planning processes and options for mitigating that risk, but also found that methods and assumptions used to analyze this risk and the impact on the selection of a preferred resource portfolio varied considerably across utilities.

Despite recommendations made over twenty years ago (Eto, 1990), inter-comparisons of resource planning assumptions, techniques, and outcomes are still uncommon and, if undertaken, do not provide much insight into planning trends across an entire region due mostly to reporting differences among resource plans. In this article, we identify where data is unavailable and inconsistently reported, while providing a summary of WECC loads and resources and highlight risks resource planners consider while developing their IRPs.

3. Important steps in the resource planning process

Long term resource planning involves three fundamental steps: (1) developing a load forecast for the planning horizon; (2) determining portfolios of existing and future resources for meeting that demand; and (3) evaluating the cost and risk of candidate resource portfolios. Each of these topics is the subject of countless papers and textbooks, so we provide only a brief summary here for context.

3.1 Load forecasts

Development of the load forecast is the foundational step in the resource planning process. Sophisticated modeling techniques are used to project energy consumption and peak demand for a variety of customers over the planning horizon. Many factors affect future demand, including weather, population, consumer behavior, technology adoption, DSM effectiveness, and economic trends. Accurately forecasting any one of these variables is difficult. It is nearly impossible to accurately predict them all with a high degree of precision. Because these forecasts are so important to the rest of the analysis, LSEs (or hired consultants) often take a year or more to develop and defend their demand projections. Consequently, by the time the final IRP is scrutinized and published, the load forecast is often out-of-date.

Load forecasts are typically reported in MWh of energy consumption, MW of coincident peak power demand, or both. Utilities often report aggregate consumer load prior to energy efficiency or demand response (DR) programs. Total annual energy consumption is a guide for what an LSE's future sales will be; coincident peak power is a measure of how much power will be required on the most demanding day of each year.

3.2 Resource portfolios

Once future load is projected, candidate portfolios of supply and DSM resources can be constructed to meet the anticipated load. Each utility first characterizes potential resources using a broad set of criteria, including availability of existing resources and contract renewals; projected fuel and environmental cost adders; capital, fixed, and variable costs of new resources; access to fuel and transmission infrastructure; the possibility of future local-state-federal regulations; and financial return on investment.

LSEs construct a number of candidate resource portfolios, which include some combination of existing and future generation, contracts, and DSM resources. The portfolio of resources that best satisfies the LSE's criteria when comparing the portfolios (e.g., least-cost, lowest risk) becomes the *preferred* portfolio. The preferred portfolio along with the load forecasts make up the loads and resource (L&R) table, which is often submitted to government regulators.

3.3 Portfolio risk and uncertainty

There are many sources of risk in the utility planning process including uncertainty about future fuel prices, legislation, weather, construction timelines, and energy demand. An inaccurate prediction of one variable (e.g., future natural gas price) can have a significant impact on expansion options, the ability of the LSE to meet future demand, the costs to the utility—and ultimately the customers. Often, multiple types of uncertainties can compound, which makes long-term risk management even more difficult. For example, if future customer load grows faster than expected and there are delays in the construction of a new power plant, the LSE may be forced to purchase electricity from potentially volatile wholesale electricity markets.

LSEs use several techniques to assess risk and uncertainty in their IRPs. Hirst and Schweitzer (1989) reviewed several long-term electric utility resource plans and provide a useful summary of the four basic analytical techniques used to evaluate uncertainty: scenario, portfolio, sensitivity, and probabilistic analysis (Table 1).

Table 1. Techniques to incorporate uncertainty in electric utility resource planning activities

Technique	Definition (adapted from Hirst and Schweitzer, 1989)
Scenario analysis	Alternative visions of the future are developed, appropriate combinations of resources are identified that best fit each future, and the best options are combined into a unified plan.
Portfolio analysis	Multiple portfolios (i.e., combinations of future resource options) are developed with each meeting a different corporate objective.
Sensitivity analysis	Key factors of candidate resource plans and portfolios are varied to see how they respond to these variations.
Probabilistic analysis	Probabilities are assigned to different values of key uncertain variables (possibly identified through the sensitivity analysis). Outcomes are identified that are associated with different values of the key factors in combination. Results often include the expected outcome and probability distribution for these key factors (e.g., natural gas prices).

4. Data Sources and Methods

WECC is one of the eight reliability councils of the North American Electric Reliability Corporation (NERC), and includes the Western U.S., Alberta, British Columbia, and the NERC Baja region (NERC, 2012a). WECC utilities generated 856,656 GWh of electricity in 2011, which represented 18.9% of generation in NERC (NERC, 2012b).

4.1 Resource plans and preferred portfolios

There are over 200 LSEs operating within WECC. The 38 LSEs included in this study represent, in aggregate, 90% of WECC generation, based on their 2011 generation reported by NERC (see Table 2). LSEs are organized in Table 2 in descending order by total annual generation to help distinguish the larger and smaller LSEs. The first two LSEs accounted for almost 25% of WECC energy generation in 2011. The first six represented half of WECC. The last LSE on the list represented less than 0.3% of WECC generation in 2011. The table also includes plan horizon and publication year.

Table 2. Load serving entities and resource plan information

	LSE Abrev.[1]	Load Serving Entity (LSE)	Percent WECC[2]	Plan Horiz. (yrs)	Preferred Portfolio	Capacity Expansion and Risk Assessment Models	Plan Reference[3]
1	PG&E	Pacific Gas & Electric[4]	12.27%	10	Base Case	Plexos Solutions	(CPUC, 2010)
2	SCE	Southern California Edison[4]	12.09%	10	Base Case	Plexos Solutions	(CPUC, 2010)
3	PacifiCorp	PacifiCorp	8.03%	10	Preferred Portfolio	Integrated Planning Model / MIDAS / System Optimizer	(PacifiCorp, 2011)
4	BChydro	British Columbia Hydro & Power Authority	7.07%	20	Base Resource Plan	System Optimizer / HYSIM	(BChydro, 2012)
5	AESO	Alberta Electric System Operator	6.86%	20	Base Case		(AESO, 2012)
6	PSCo	Public Service Company of Colorado (Xcel)	3.70%	25	Base Case	Strategist	(PSCo, 2011)
7	APS	Arizona Public Service Company	3.57%	15	Base Case (least cost)	Ventyx PROMOD IV	(APS, 2012)
8	LADWP	Los Angeles Department of Water and Power	3.37%	25	Recommended Case	Ventyx PROSYM / Planning and Risk	(LADWP, 2011)
9	SRP	Salt River Project	3.33%	5	Base Case (only case)		(SRP, 2011)
10	PSE	Puget Sound Energy, Inc	2.89%	20	Base Case	AURORAxmp / Portfolio Screen Model (PSM III)	(PSE, 2011)
11	NVPower	Nevada Power Company[5]	2.53%	25	Preferred Plan	PROMOD / Capital Expenditure Recovery	(NVPower, 2012)
12	SDG&E	San Diego Gas & Electric[4]	2.44%	10	Base Case	Plexos Solutions	(CPUC, 2010)
13	PGE	Portland General Electric Company	2.23%	25	Preferred Portfolio	AURORAxmp	(PGE, 2011)

14	Idaho	Idaho Power Company	1.75%	20	Preferred Portfolio	AURORAxmp	(Idaho, 2011)
15	TEP	Tucson Electric Power Company	1.59%	10	Reference Plan		(TEP, 2012)
16	SMUD	Sacramento Municipal Utility District	1.31%	10	Base Case (only case)		(SMUD, 2010)
17	PNM	Public Service Company of New Mexico	1.27%	20	Action Plan	Strategist	(PNM, 2011)
18	SCL	Seattle City Light	1.19%	20	Preferred Portfolio	AURORAxmp	(SCL, 2010)
19	Avista	Avista Corporation	1.12%	20	Preferred Strategy	AURORAxmp / PRiSM	(Avista, 2011)
20	NW	NorthWestern Corp. (NorthWestern Energy)	1.08%	20	Multiple (6 portfolios)	PCI GenTrader	(NW, 2011)
21	SP	Sierra Pacific Power Company[5]	1.02%	25	Preferred Plan	Ventyx Promod	(SP, 2010)
22	EPE	El Paso Electric Company	0.97%	20	Optimal Expansion Plan		(EPE, 2012)
23	WMPA	Wyoming Municipal Power Agency	0.86%	25	Preferred Plan	Strategist	(WMPA, 2011)
24	Snohomish	PUD No. 1 of Snohomish County	0.84%	12	Preferred Plan	AURORAxmp	(Snohomish, 2010)
25	BHP	Black Hills Power	0.64%	20	Base Plan (Least Cost)	Ventyx Strategic Planning	(BHP, 2011)
26	Cowlitz	PUD No. 1 of Cowlitz County	0.60%	18	Preferred Portfolio	AURORAxmp	(Cowlitz, 2008)
27	TP	City of Tacoma DBA Tacoma Power	0.59%	20	Preferred Plan (Least Cost)	Aurora / Genesis hydro load / Portfolio Strategist	(TP, 2010)
28	TriState	Tri-State Gen. & Trans. Assoc. Inc	0.55%	20	Base Case	System Optimizer / Planning and Risk	(Tristate, 2010)
29	Deseret	Deseret Gen. & Trans. Coop.	0.55%				LBNL Survey
30	Clark	Clark Public Utilities	0.53%	20	Multiple (3 portfolios)		(Clark, 2012)
31	Grant	PUD No. 2 of Grant County	0.48%	20	Least Cost		(Grant, 2009)
32	Chelan	PUD No. 1 of Chelan County	0.44%	10	Base Case	Resource Portfolio Strategist	(Chelan, 2012)
33	IID	Imperial Irrigation District	0.42%	4	EC3 repowered	Ventyx PROSYM	(IID, 2010)
34	Basin	Basin Electric Power Cooperative	0.40%				LBNL Survey
35	CAZ	Central Arizona Water Conservation District	0.39%				LBNL Survey
36	PRPA	Platte River Power Authority	0.38%	10	Recommended		(PRPA, 2012)
37	Alcoa	Alcoa Inc	0.37%				LBNL Survey
38	EWEB	Eugene Water & Electric Board	0.29%	20	Recommended	AURORAxmp	(EWEB, 2011)

Notes:

[1] LSE abbreviation for convenient reference within this

[4] Percent for PG&E, SCE, and SDG&E based on 2011

report

2 Percent of WECC generation based on NERC 2011 energy production (NERC, 2012b)

3 Plan reference year is also the latest publication year as of August 2012

energy production for CAISO (NERC 2012b) and is proportional to the LSEs 2012 forecast

5 NVPower and SP merged into NV Energy, but continue to file separate IRPs until pending interconnection line is completed in January 2014

IRPs are not released annually so plan vintage is a key issue when interpreting the aggregated results across LSEs. The majority of the plans we reviewed were released between 2010 and 2012, but many of the assumptions (e.g., fuel price forecasts, future policies) are developed more than a year before the published date of the plan. For a few LSEs, the most recent plans were published prior to the U.S. financial crisis. As a result, consumer demand and resource portfolios for these LSEs will likely not represent their current expectations.

We obtained each plan from the LSE website and attempted to identify the *preferred portfolio*. Many identify their top performing portfolio as the preferred portfolio, but others refer to it as the base case, least cost, most cost-effective, or by scenario number. Some did not identify any preferred portfolio, in which case we use their base case.

4.2 Supplemental surveys

Most LSEs reported sufficient detail about existing and incremental generation and planned retirements. However, some IRPs did not include information about existing or future generation. Consequently, we also sent supplemental surveys to each of the 34 LSEs for which we reviewed an IRP and we contacted a few LSEs who did not publish a plan. This survey was an opportunity to verify our interpretations of their respective plans and give planners an opportunity to update their generation forecasts since publication of their IRP. The supplemental survey provided us with the current and future mix of generation; however, the surveys did not ask the LSEs to provide other valuable resource planning information such as load forecasts, carbon tax assumptions, or scenario descriptions.

5. How consistent is the collection and reporting of resource planning-related data across the Western United States?

One consistent trend we discovered in this review of resource plans is that critical planning assumptions are *inconsistently* collected and reported by the LSEs. In this analysis, we focus on a subset of long-term planning assumptions for the purpose of demonstrating a common set of issues associated with resource planning data. For example, we did not focus on supply-side assumptions related to capacity factors or capital costs. This is a reflection of differences in local, state, and regional reporting requirements—and these inconsistencies affect our ability to compare many planning assumptions. In this section, we highlight the availability (and consistency) of planning information to better frame the subsequent results of our study.
All 34 IRPs we reviewed included some level of detail about current resources and most identified a preferred or recommended portfolio of future resources. Six of the 34 LSEs we studied did not respond to the supplemental survey (PSCo, SDG&E, WMPA, Grant, PRPA, and EWEB). However, the survey allowed us to collect generation information from four additional LSEs for which we did not find publicly-released plans (Deseret, Basin, CAZ, and Alcoa).

Figure 1 depicts the number of LSEs that publicly-released IRPs, responded to the supplemental survey, and reported supply-side capacity information. A black dot indicates that data exists and a blank cell notes where data is unavailable. LSE numbers across the top correlate to the LSEs described in Table 2. We present the data in this manner because each utility represents a different percentage of WECC and knowing which provided the data will indicate the scope of any aggregated totals. While this may seem unnecessary for the densely-populated data in Figure 1, this format will provide additional insight when we view less common data. Parenthetical numbers next to the row headers indicate the number of LSEs that reported information for the relevant row (e.g., IRPs (34) means that we found and reviewed IRPs from 34 LSEs).

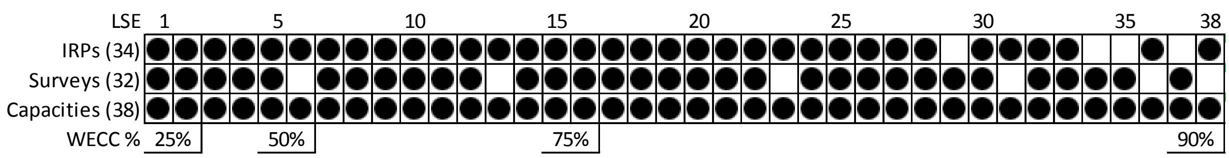


Figure 1. LSEs with publicly-released IRPs, responded to the supplemental survey, and reported supply-side capacity information

We collected both nameplate and available capacity; unfortunately, many of the LSEs only reported one or the other making it difficult to aggregate our results into a single Western U.S. capacity estimate. If only one capacity number was provided, we assumed that available capacity was equivalent to nameplate capacity. This was a reasonable assumption for the majority of baseload (thermal) generators, which typically run at (or near) nameplate capacity. However, this assumption could be problematic for intermittent renewable generators which have available (operational) capacity or peak-coincident values that are typically much lower than nameplate capacity. The aggregation of a mix of available and nameplate capacities into a single capacity number will underestimate total installed capacity.

Most LSEs reported both peak load and annual energy forecasts. However, some did not report both (see Figure 2). A higher share of LSEs, especially the smaller utilities, did not report anticipated amounts of EE or DR[3] in their IRP.

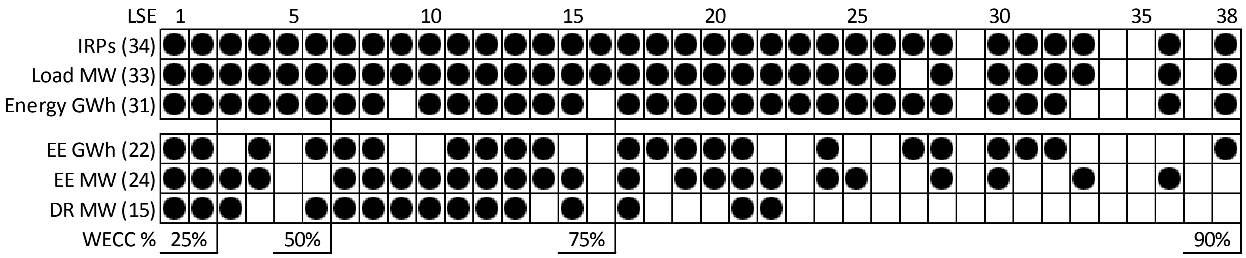


Figure 2. Load, energy, and DSM forecast data availability

We will show in the next section that the LSEs here anticipate significant load growth over the coming decades, and plan to increase generation capacity by tens of thousands of MWs. Despite the reported need for new resources, we found that LSEs rarely reported additions (or improvements) to transmission interconnections, fuel delivery systems, and energy storage facilities in the IRP. Several LSEs mentioned pilot projects or alluded to a need for future evaluation of infrastructure additions, but this general lack of data is apparent in Figure 3. Seventeen LSEs reported infrastructure activities, but only eight identified transmission interconnections with their neighbors.

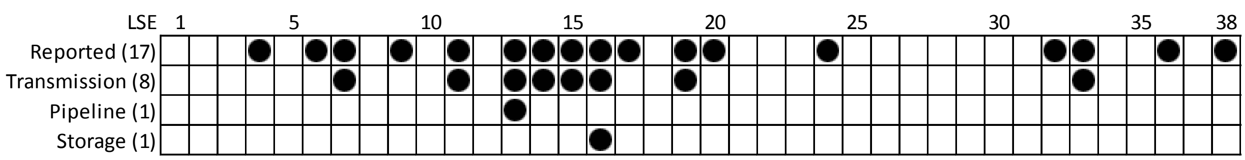


Figure 3. Transmission interconnections, fuel pipelines, and energy storage data availability

[3] Most utility IRP plans do not treat time-based rates as a potential DR resource, unless coupled with enabling technology.

6. What are Western U.S. electric utility planners assuming about the future growth of electricity demand and supply-side resources?

6.1 Demand-side assumptions

Energy and Load forecasts

Three of the 34 IRPs we evaluated, did not provide annual energy (GWh) forecasts and one did not provide a peak demand (MW) forecast. The remaining 31 LSEs reporting this information represented 83.2% of WECC in 2011. If we assume these 31 LSEs will continue to represent the same share of WECC, then the region is expected grow from 857 TWh (2011) to 1,011 TWh by 2020.

Peak power represents a single hour each year when an LSE anticipates the highest demand. However, this event does not occur at the same time of day or season for all LSEs. Annual peak load occurs in the afternoon during the hottest summer day for many western utilities; others report peak loads during the winter. Consequently, we compare load shapes using load factor[4] (LF), which is the ratio of average demand (GWh/8760h) and peak demand (GW).
Table 3 shows the load for each utility in 2012 and 2020 and the corresponding LF. Most LSEs have values between 50-70%, with both a median and average of 58%. One notable exception is AESO with LF of 80%.[5] Most of the LSEs forecast between 1-2% annual growth in demand (without DSM); however, AESO and APS are projecting faster demand growth of about 4% and 3% respectively.

DSM forecasts

DSM programs, often considered alternatives to supply-side resources, reduce the amount of energy and peak load an LSE will need to meet in future years. Energy efficiency (EE) programs seek to reduce overall consumer energy consumption replacing inefficient components. If the saved energy is coincident with peak demand, then the utility will also see a reduction in peak power from EE programs. Demand Response (DR) programs seek to shift demand away from the system peak demand, but will not likely reduce energy consumption and will only reduce demand if the DR contract is activated.

[4] A high LF represents a relatively constant system load. In contrast, a low LF indicates that the utility serves a very large peak demand relative to average demand. Peak demand drives a utility's need for new capacity and investments are made to maintain the ability to serve the maximum demand.
[5] It should be noted that AESO has a relatively high share of consistent, industrial load in large part to oil sands-related production activities. Industrial-related consumption represents nearly 60% of AESO's total demand for energy.

Table 3. Projection of Load, Load Factors (LF), and DSM impacts by 2020

	2012			2020											
	Load			Load before DSM			Ann. Growth[1]		EE Measures[2]		DR[2]	% Savings[3]		LF w/DSM[3]	
LSE	GWh	MW	LF	GWh	MW	LF	GWh	MW	GWh	MW	MW	GWh	MW	LF	%Δ
1 PG&E	112,153	21,988	58%	122,632	24,310	58%	1.1%	1.3%	6,817	2,496	2,001	5.6%	10.3%	61%	5.2%
2 SCE	110,505	24,142	52%	121,538	26,875	52%	1.2%	1.3%	6,764	2,648	2,842	5.6%	9.9%	54%	4.8%
3 PacifiCorp	64,958	10,716	69%	76,137	12,607	69%	2.0%	2.1%	-	1,189	250	-	9.4%	76%	10.4%
4 BChydro	58,603	10,651	63%	71,659	12,923	63%	2.5%	2.4%	4,615	566	-	6.4%	4.4%	62%	-2.2%
5 AESO	65,132	9,548	78%	92,269	13,200	80%	4.4%	4.1%	-	-	-	-	-	80%	-
6 PSCo	31,046	6,391	55%	33,652	6,905	56%	1.0%	1.0%	411	-	267	1.2%	0.0%	55%	-1.2%
7 APS	32,370	7,234	51%	40,987	9,372	50%	3.0%	3.3%	6,192	1,186	280	15.1%	12.7%	49%	-2.8%
8 LADWP	26,235	5,650	53%	28,582	6,160	53%	1.1%	1.1%	1,302	175	200	4.6%	2.8%	52%	-1.8%
9 SRP	-	6,807	-	-	-	-	-	-	-	52	322	-	-	-	-
10 PSE	22,331	5,073	50%	26,267	5,806	52%	2.0%	1.7%	-	689	126	-	11.9%	59%	13.5%
11 NVPower	21,816	5,557	45%	23,900	5,918	46%	1.1%	0.8%	592	258	279	2.5%	4.4%	47%	2.0%
12 SDG&E	22,284	4,658	55%	24,740	5,157	55%	1.3%	1.3%	1,389	544	302	5.6%	10.5%	58%	5.5%
13 PGE	23,479	4,236	63%	28,163	5,002	64%	2.3%	2.1%	1,807	624	105	6.4%	12.5%	69%	6.9%
14 Idaho	16,628	3,577	53%	18,764	4,190	51%	1.5%	2.0%	1,384	351	-	7.4%	8.4%	52%	1.1%
15 TEP	9,686	2,492	44%	11,678	2,829	47%	2.4%	1.6%	-	325	52	-	11.5%	53%	13.0%
16 SMUD	-	3,267	-	-	3,677	-	-	1.5%	-	-	-	-	-	-	-
17 PNM	10,467	1,992	60%	12,021	2,288	60%	1.7%	1.7%	823	149	92	6.8%	6.5%	60%	-0.3%
18 SCL	10,658	1,880	65%	12,107	2,121	65%	1.6%	1.5%	1,083	-	-	8.9%	-	59%	-8.9%
19 Avista	10,941	1,903	66%	11,090	1,873	68%	0.2%	-0.2%	723	140	-	6.5%	7.5%	68%	1.0%
20 NW	6,510	1,192	62%	7,210	1,319	62%	1.3%	1.3%	473	99	-	6.6%	7.5%	63%	1.0%
21 SP	8,873	1,611	63%	8,924	1,597	64%	0.1%	-0.1%	101	100	9	1.1%	6.3%	67%	5.5%
22 EPE	8,303	1,698	56%	9,679	2,111	52%	1.9%	2.8%	-	64	61	-	3.0%	54%	3.1%
23 WMPA	268	50	61%	323	60	61%	2.3%	2.2%	-	-	-	-	-	61%	-
24 Snohomish	7,445	1,469	58%	8,482	1,625	60%	1.6%	1.3%	917	202	-	10.8%	12.4%	61%	1.8%
25 BHP	2,306	414	64%	2,606	464	64%	1.5%	1.4%	-	3	-	-	0.6%	65%	0.7%
26 Cowlitz	5,144	816	72%	5,327	870	70%	0.4%	0.8%	-	-	-	-	-	70%	-
27 TP	5,277	-	-	5,956	-	-	1.5%	-	523	-	-	8.8%	-	-	-
28 TriState	15,734	2,705	66%	18,144	3,087	67%	1.8%	1.7%	1,605	309	-	8.8%	10.0%	68%	1.3%
29 Deseret	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Clark	4,844	1,149	48%	5,455	1,303	48%	1.5%	1.6%	714	165	-	13.1%	12.7%	48%	-0.5%
31 Grant	4,690	858	62%	4,916	926	61%	0.6%	1.0%	202	-	-	4.1%	-	58%	-4.1%
32 Chelan	1,664	420	45%	1,868	496	43%	1.5%	2.1%	162	-	-	8.7%	-	39%	-8.7%
33 IID	-	1,185	-	-	-	-	-	-	-	51	-	-	-	-	-
34 Basin	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35 CAZ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36 PRPA	3,234	654	56%	3,745	804	53%	1.9%	2.6%	-	29	-	-	3.6%	55%	3.7%
37 Alcoa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38 EWEB	2,628	520	58%	2,838	560	58%	1.0%	0.9%	377	-	-	13.3%	-	50%	-13.3%
Total	**726,214**	**152,504**		**841,660**	**166,434**		**1.9%[4]**		**38,976**	**12,414**	**7,188**	**6.4%[5]**	**8.6%[6]**		
Median			**58%**			**59%**	**1.5%**	**1.5%**				**6.5%**	**8.4%**	**59%**	**1.1%**

Notes

[1] Compound annual growth rate from 2012-2020 prior to DSM

[2] New EE and DR measures beginning in 2013. Measures implemented prior to 2013 are included in the 2012 Load

[3] Savings from EE only. DR impacts represent a capability, but the programs might not actually be called

[4] Aggregate annual growth rate

[5] Percent savings only from utilities reporting EE measures. Loads from those not reporting savings are not included

[6] Percent savings only from utilities that reported peak reduction from EE. Potential DR savings in addition to this.

Many of the IRPs we reviewed discussed various EE programs (e.g., lighting measures, weatherization), and about two-thirds (22 of 31) of the LSEs who provided an annual energy forecast also reported EE savings projections. However, since utilities often publish separate DSM program plans, only a few LSEs reported savings estimates for these different programs in the IRP. However, in aggregate, these 22 LSEs expect to reduce their annual energy demand in 2020 by 39 TWh (6.4%) with a median savings of 6.4% which differs somewhat from the cumulative energy savings of 8.4% as reported in Barbose et al. (2013).[6] Four utilities (APS, Snohomish, Clark, EWEB) are forecasting that EE measures will reduce energy by over 10%. These will also reduce peak load by 12.4 GW (8.6%) through 2020. Interestingly, Table 3 shows that LSEs anticipating relatively higher annual load growth rates also anticipated a relatively higher share of savings from energy efficient measures.

Very few LSEs reported DR savings disaggregated by program type (e.g., interruptible/curtailable loads, dynamic pricing, direct load control), so we only report aggregate DR potential for all programs. DR impacts represent a capability, but might not actually be called. However, if they are activated, those utilities reporting DR expect to reduce peak load up to 7.2 GW beyond the EE load savings.

For some utilities, the impact of DSM programs is unclear. For example, SCL only reported energy savings from EE measures; it is possible that these savings have no coincidence with peak power demand, but this was not explicitly stated in the IRP. Also, PacifiCorp only reported peak load savings from EE and DR, but did not report the energy savings from the EE measures. In practice, planning decisions about how much DSM to acquire are more often made outside of the broader IRP process, so DSM is often an "input" to the resource plan, rather than a potential resource considered within the candidate portfolios. However, while utilities often publish separate DSM program plans,[7] long-term planners and program administrators would benefit from more information about the size, cost, successes, and challenges of DSM programs within the context of the IRP.

6.2 Supply-side assumptions

Utilities typically identify the amount of existing capacity, incremental new capacity, and anticipated retirements over their planning horizon. Some provide detailed information for both existing and planned supply-side resources including fuel type, location, size, and capacity factor; however, many do not. Nonetheless, we report aggregate estimates of existing, planned, and retiring generation disaggregate by fuel type when possible.

Retirements and new incremental generation

Changes in long-term capacity will likely come from a combination of new capacity, planned retirements, and a decline in contracted supply. For this study, we consider capacity changes (e.g., new capacity, retirements) after 2012. Figure 4 shows that total installed nameplate capacity from all 38 LSEs was 198 GW in 2012, which is forecasted to grow ~20% by 2030. Not all IRPs include a forecast through 2030, so the analysis becomes less useful in later years. Since

[6] Barbose et al. (2013) estimate cumulative energy savings in 2020 equal to 8.4% of total Western retail sales in 2020 (compared to the 6.4% number based on information from the IRPs). One possible contributor to this discrepancy is that some of the IRP savings projections may not extend all the way to 2020 (e.g., the Energy Trust of Oregon's strategic plan only has savings targets out to 2017), whereas the Barbose et al. (2013) ratepayer EE projections extrapolate beyond the end of each LSEs' planning period.

[7] In practice, planning decisions about how much DSM to acquire are more often made outside of the broader IRP process, so DSM is often an "input" to the resource plan, rather than a potential resource considered within the candidate portfolios.

physical resources are generally relicensed after their book-life or contract expiration year, we extend the last plan year of the respective resource portfolios of these shorter plans through 2030 to help put the longer-term forecasts in context.

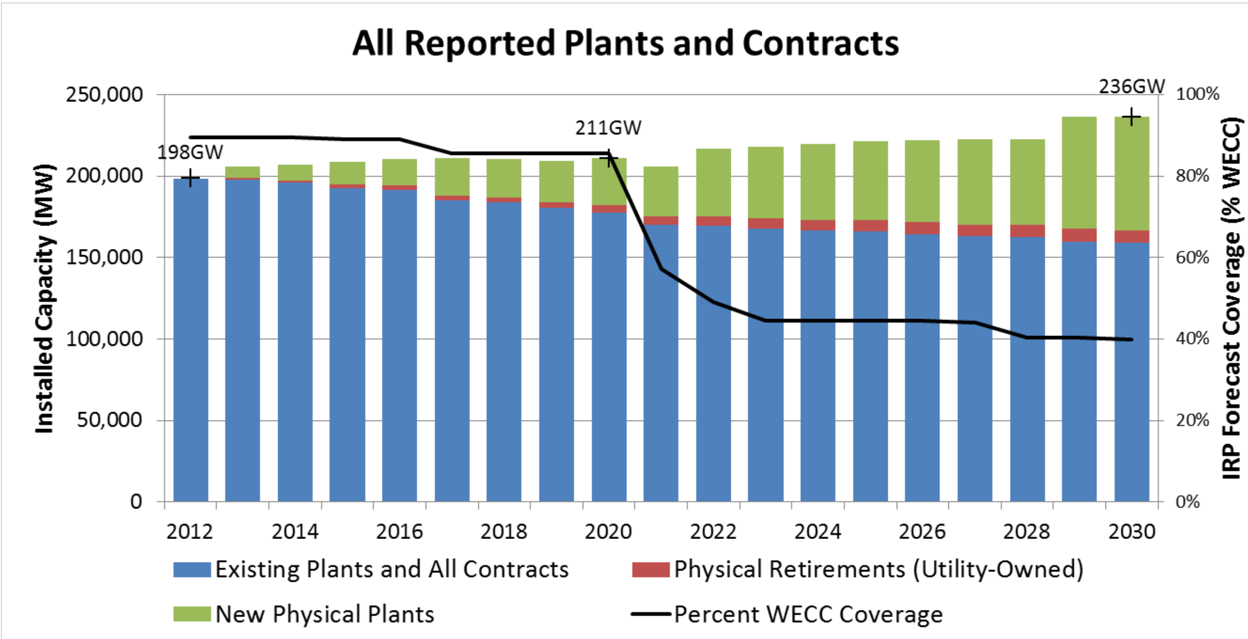


Figure 4. Installed nameplate capacity.

New Physical Plants includes any new resource with an in-service date during or after 2013. This includes physical plants that were already under construction or in the procurement process when the IRP was published. It also includes new contracts that represent new construction. The latter distinction is sometimes hard to decipher from the IRPs, so it is likely that we underestimated new physical generation; however, this would otherwise be captured under *All Contracts* so would not impact the total installed capacity.

Physical Retirements only captures what is reported explicitly in the IRP as retiring. This is almost entirely utility-owned generation, and is unlikely to include all private power or independent power producer (IPP) retirements. When a contract expires and is not renewed, the underlying physical resource could remain in service to be re-contracted with another LSE (one which we did not review) or it could be retired. The latter is particularly true in California, where many IPP plants could retire as a result of once-through cooling (OTC) regulations.[8] This level of detail about third-party resources is not provided in the IRPs. Consequently, it is likely we are underestimating retirements.

Existing Plants and All Contracts includes all existing owned capacity and all current, renewing, and future contracts (except contracts explicitly involving new construction). If an IRP identified a future resource need without indicating new incremental generation or potential contract, it is assumed to be a contract.

[8] Once-through cooling regulations prohibit the use of ocean water in the cooling of power plants, are responsible for the conversion or retirement of many natural gas-fired power plants along California's coast.

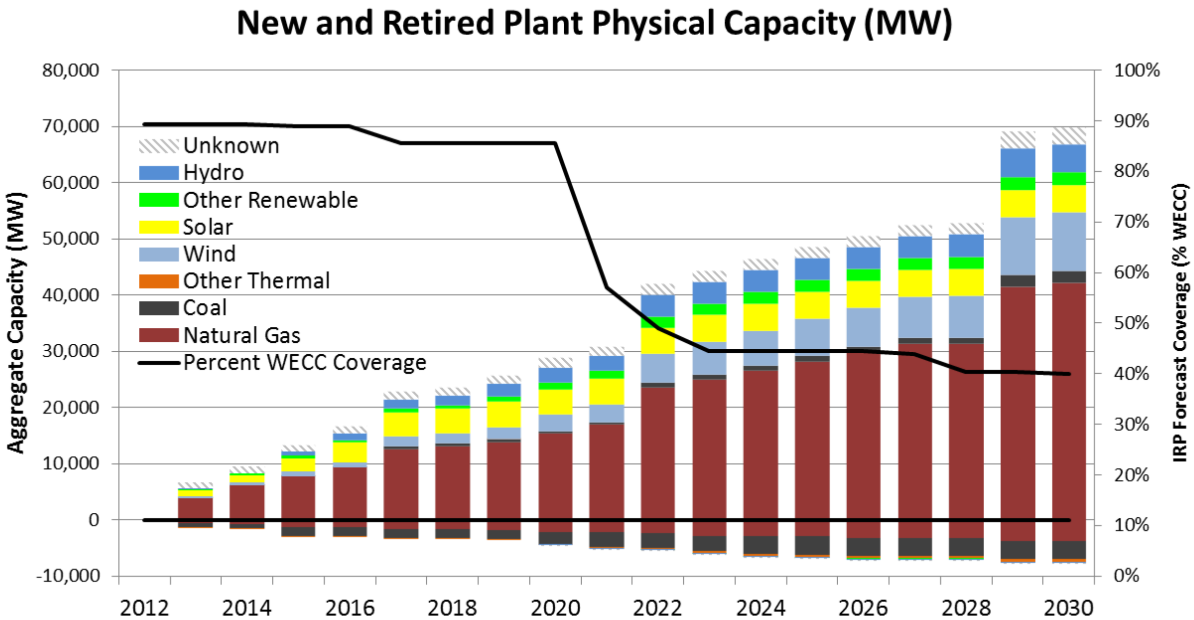


Figure 5. Planned new and retiring power plant capacity by primary fuel type.

Figure 5 shows that the fuel mix of new capacity is dominated by natural gas, while the retirements are split almost entirely between natural gas and coal-fired generation. Again, utilities representing about half of WECC have forecasts that end in 2020, so any incremental resource addition or retirement beyond 2020 represents only the other half of WECC. In the following sections, we compare cumulative retirements and new generation for 2020 and 2030.

Physical Retirements

Figure 6 depicts the share of planned retirements through 2020 and 2030. Coal and natural gas-fired units represent the vast majority (~90%) of planned retirements. Three quarters (75%) of the coal-fired retirements by 2020 will be evenly shared by APS, PacifiCorp, and LADWP. PGE, EPE and BHP account for the remaining share of retirements by 2020. NVPower (55%), SP (40%), and Idaho (5%) anticipate additional coal-fired generation retirements from 2020 to 2030.

OTC regulations are responsible for the conversion (or retirement) of many natural gas-fired power plants along California's coast. LADWP, for example, accounts for nearly two-thirds (63%) of natural gas retirements by 2020, and 75% of the retirements between 2020 and 2030. Most of the planned natural gas retirements occurring after 2020 are combined cycle combustion turbines (CCCT).

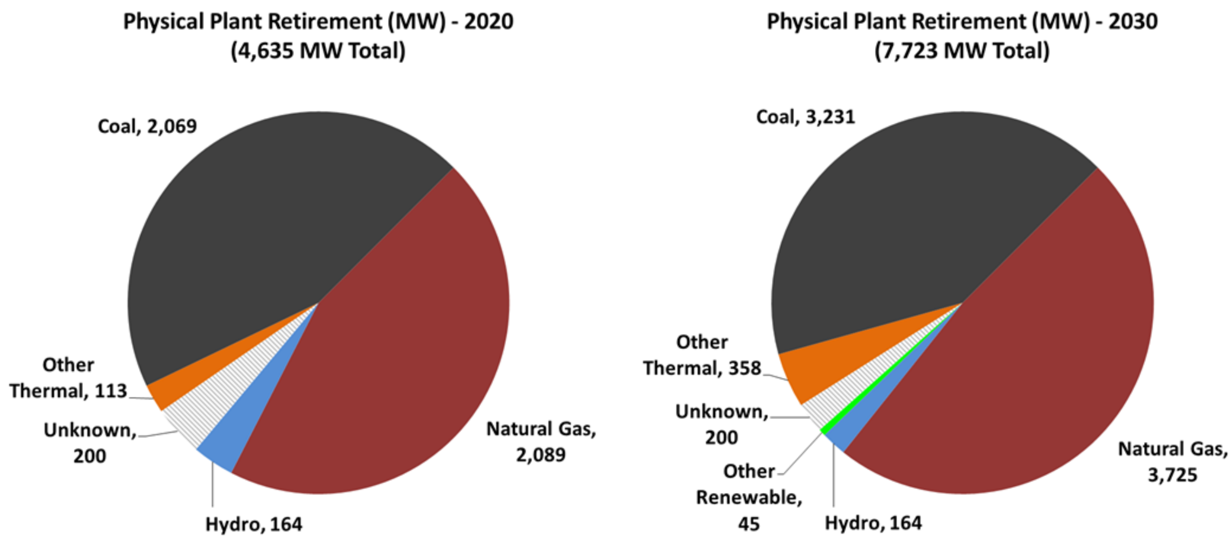


Figure 6. Anticipated power plant retirements by 2020 and 2030 (cumulative)

New Physical Plants

New generation will be dominated by natural gas-fired capacity, with significant growth in renewables (e.g., wind, solar), and some hydroelectric power (Figure 7). The majority of anticipated natural gas-fired additions through 2020 will be CCCTs (59%) and simple cycle combustion turbines (SCCTs) (26%). Most of the remaining incremental gas-fired capacity was not identified by type of unit. These natural gas additions represent projections from 20 LSEs. Beyond 2020, CCCTs and SCCTs account for 54% and 19% of additional gas-fired capacity, respectively, with the remainder consisting of generic natural gas-fired capacity. Fourteen LSEs project natural gas capacity expansion between 2020 and 2030, dominated by AESO (52%), NVPower (10%), LADWP (9%), and APS (9%) which account for 80% of the additional 27 GW of natural gas-fired generation between 2020 and 2030.

Despite an uncertain regulatory environment and low natural gas prices, a few LSEs are planning to add coal-fired generation over the coming decades. These coal additions account for only 2% of all planned new capacity by 2020 and 3% through 2030; however, EIA projects planned coal additions across the U.S. to account for 13% of all new capacity by 2020 and 2030 (EIA, 2013). Within WECC, AESO (76% share of new coal capacity) and Deseret (22%) anticipate new coal-fired generation coming online by 2020, with PacifiCorp upgrading their coal facilities to account for the remainder. AESO and BHP are assuming additional new coal-fired capacity will be built beyond 2020, with AESO accounting for 94% of the additional coal capacity between 2020 and 2030.

At the same time, AESO also reported the largest share of incremental wind generation, accounting for half (5,221 MW) of all new wind capacity planned between 2012 and 2030. In the short term, AESO is one of six LSEs planning new wind through 2020, which include PacifiCorp (47%), AESO (19%), SCE (18%), TriState (9%), PSE (7%), and a small amount from PGE. After 2020, eight LSEs project even more new wind capacity expansion. In all, PacifiCorp and AESO account for 71% of all new wind projected from today through 2030.

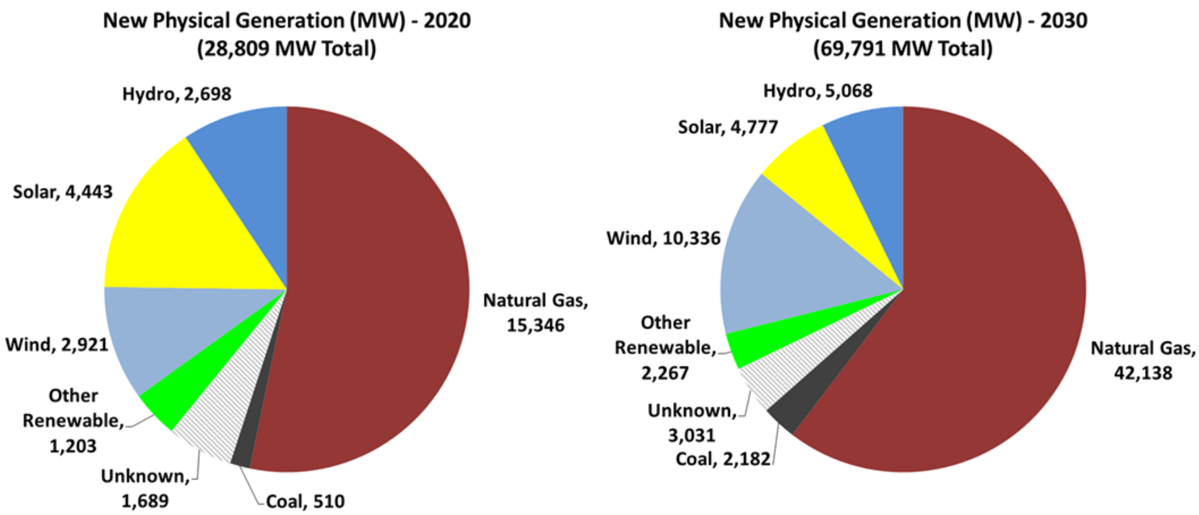


Figure 7. New generation capacity by 2020 and 2030 (cumulative)

NVPower and SCE are planning new solar thermal facilities through 2020 which, combined, are 5% of new solar generation; however, the vast majority of new solar is photovoltaic (PV). Twelve additional LSEs are projecting expansion of solar PV through 2020, with SCE and APS accounting for 77% and 14% of new solar during this period, respectively. Only a small fraction is reported as distributed generation (DG), but it is unclear if little DG is planned or if it is just not reported in the IRPs. Beyond 2020, a surprisingly small amount of solar PV expansion was identified.

BC Hydro anticipates the largest share of new hydroelectric resources through 2020, accounting for 78% of new hydro generation capacity. Of the remainder, SMUD accounts for 15%, PSE (5%), Idaho (2%), and a small amount from Snohomish. After 2020, AESO and BC Hydro make up the bulk of additional hydro capacity, 51% and 46%, respectively.

There are inherent challenges with increased penetration of variable generation sources like wind and solar, which can be addressed with increased balancing area cooperation and greater system flexibility (Lew et al., 2010). However, without broader cooperation and planning, these challenges can lead to peaking plants built predominantly to support intermittent renewable generation. (e.g., Cappers et al., 2011; NERC, 2009). Our evaluation of IRPs only uncovered one plan (SRP), which indicated that two new generators will likely be built specifically for the purpose of supporting intermittent renewables. In our supplemental survey, we asked resource planners to indicate whether any of their planned additions were "primarily" to provide reliability support for intermittent generation. SRP revised their assumption, now anticipating four units by 2020—with a total capacity of 819 MW—to support intermittent generation within their planning territory[9] (SRP, 2012); yet SRP also reports only 204 MW of all renewable capacity additions through the same period. Another, TEP, indicated that three new units by 2024—totaling 270 MW—are planned to support increased penetration of solar generation, which they reported to be less than 30 MW. Of the remaining LSEs, 10 specifically indicated

[9] SRP (2012) indicated that these natural gas units "would be used for both integrating intermittent renewable generation resources into SRP's system and meeting peak demand requirements".

that all of their new generation was being built primarily for other reasons, and, unfortunately, 19 LSEs did not answer the question.

Future fuel mix

Relative shares of wind and solar could grow by 250% and 380%, respectively, by 2030; however, they still represent a relatively small share of the total mix of generation. Traditional thermal generation represents a relatively constant share of ~55% of the mix annually. Most retiring coal-fired generation will be replaced by natural gas and, to a lesser extent, wind and solar (Figure 8).

We were not always able to identify the fuel type of existing and new generation due to incomplete or inconsistent reporting. For existing resources, this could occur when LSEs obtained electricity through an undesignated contract or identified a plant name in the IRP which could not easily be cross-referenced using external sources of information. For planned generation, several IRPs report that the lack of information about fuel source is due to indecision about what future resources will be most effective given the uncertain planning environment over the next few decades. The "Unknown" fuel source share decreases over time, due in part to the small number of forecasts that extend that far. Regardless, a significant portion of existing and future capacity resources are not identified by fuel type.

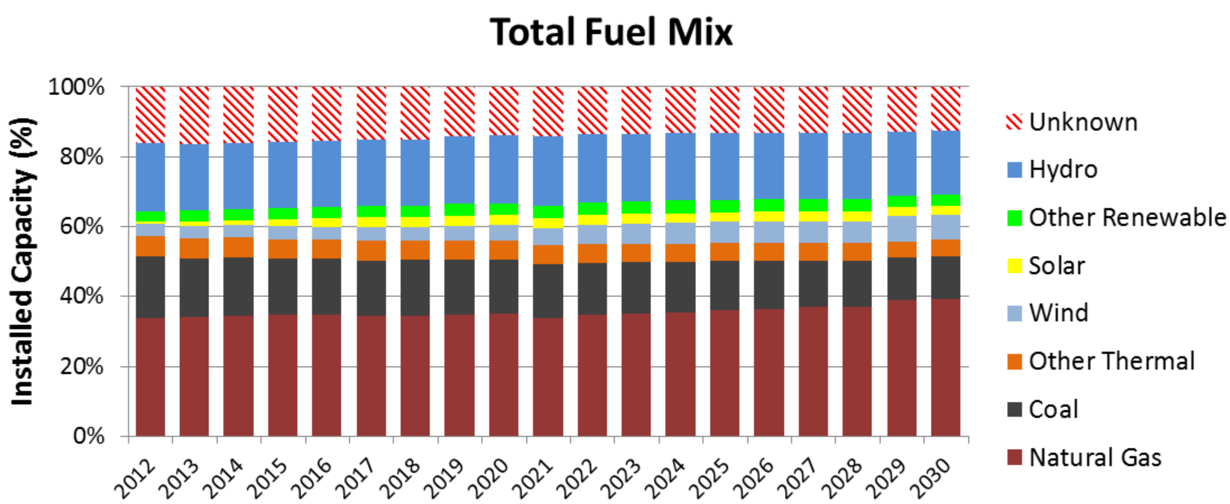


Figure 8. Share of installed capacity by primary energy source.

6.3 Electricity interconnection, energy distribution, and storage assumptions

Effective resource planning activities can inform long-term electric utility and transmission and distribution expansion efforts. Significant increases in planned generation capacity will also require new transmission interties and gas pipeline interconnections. For these reasons, we attempted to collect information from the IRPs describing planned electric transmission interties, natural gas pipeline development, and additions to energy storage infrastructure. Only half of the LSEs we studied (17 of 34) reported some level of information about planned infrastructure developments.

For electric transmission, eight LSEs anticipate 29 new interconnection projects between LSEs. Unfortunately, there is significant inconsistency in how LSEs report electricity infrastructure. For example, some indicate intertie voltage and physical length, while others list capacity in MWs as if it were a new incremental capacity resource. Figure 9 shows the count and completion year, if indicated, of planned interconnection projects that were reported for these eight LSEs.

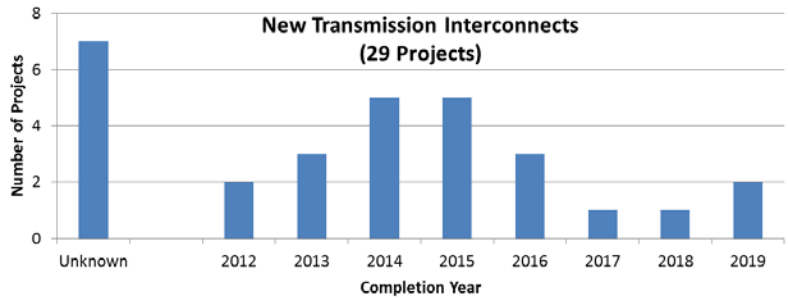


Figure 9. Count of new electric interconnection projects from eight LSEs

Much less information was available for other infrastructure additions. We could find only one LSE (PGE) that indicated activity related to a natural gas pipeline interconnection--an upgrade to an existing line. A few LSEs (e.g., PSCo, TEP, Idaho Power) considered storage options (e.g., large-scale battery storage, solar thermal, pumped-hydro capacity) in their planning analyses, and a few others alluded to energy storage pilot projects, but only SMUD is planning for new storage infrastructure (pumped-hydro). Interestingly, this facility was not listed as a new resource for generation, but as a transmission project in the "planned transmission projects" section of the SMUD IRP.

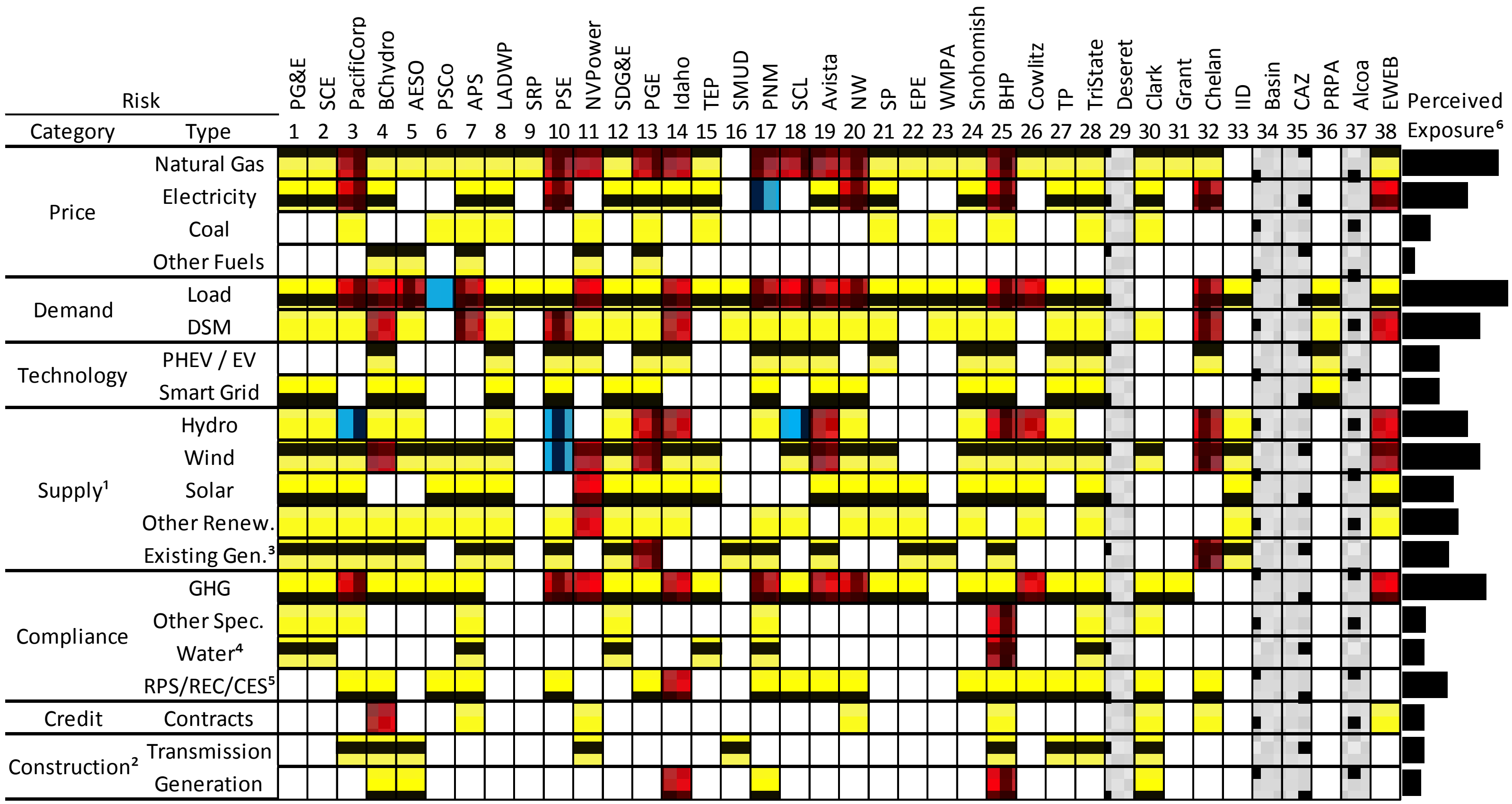
7. What types of risk do Western U.S. utilities consider and focus on in their long-term resource planning?

LSEs are confronted with many uncertainties and risks in their attempt to meet consumer demand in a cost-effective and reliable manner. Future demand may be higher than forecast due to changes in weather patterns, higher population growth, or lower DSM participation. Spot market energy prices may be higher than anticipated or unexpectedly fall. New technologies could dramatically transform the market and affect both the quantity and shape of a future load profile. The construction of a power plant could take longer than projected, increasing the construction costs and forcing the LSE to enter into a temporary supply contract until the facility is operational.

Section 3.3 introduced several analytical techniques commonly used to evaluate long-term planning uncertainty. Given this framework, we compiled LSE risk evaluation techniques and organized them into a number of risk categories. Many LSEs developed scenarios to explore portfolio performance given alternative visions of the future. Some evaluated the sensitivity of portfolio costs to a wide-range of input values. A few used the results of the sensitivity analysis to determine which uncertain inputs to evaluate using advanced statistical techniques.

Figure 10 is a comparison of utility methods used to assess uncertainty organized by a number of quantitative risk categories. A yellow box in the matrix indicates an LSE only conducted a scenario or sensitivity analysis; a blue box represents that only a probabilistic or stochastic analysis was conducted; a red box indicates that both scenario/sensitivity and probabilistic analyses were employed. Unfilled boxes represent risk categories that LSEs did not evaluate quantitatively. For example, AESO considered the price of coal in their scenarios, but did not report alternative prices beyond the base assumptions. There are very few examples of probabilistic-only analyses (blue boxes), such as PSCo which hired a consultant to conduct a stochastic analysis to provide the most likely load forecast. PSCo used this load forecast in their scenario analyses. In general, larger LSEs undertook more comprehensive risk assessments than smaller LSEs.

We found that a number of risk categories were evaluated by LSEs consistently. For example, almost all conducted scenario/sensitivity analyses for natural gas and electricity prices. This finding is not surprising since these two inputs have significant and direct impacts on LSE operational costs. In addition, uncertainty about future load and the availability of DSM also received considerable attention, as did the availability of lower cost supply-side resources. The data bars on the right of the figure represent an aggregation of perceived exposure to a particular risk category. The relative length of the data bar is computed by the summing how many LSEs addressed that particular risk type in their planning (i.e. we assigned one point for the use of scenario or probabilistic analysis and two points when both were used). Using this method, future demand, natural gas prices, and GHG compliance uncertainties dominate LSE risk assessments, followed closely by uncertainty about the cost and performance of future wind resources and DSM participation.



key:
- Scenario or Sensitivity Analysis
- Probabilistic Analysis
- Scenario/Sensitivity and Probabilistic
- Not identified in plan
- Plan not available
- Aggregate of perceived exposure to risk

notes:
[1] All LSEs considered traditional future generation resources, so not summarized here
[2] Risk to construction time or cost overruns
[3] LSE considered changes to existing generation such as early retirements or upgrades
[4] Risk to water contamination or exceeding use limits
[5] LSE considered some form of energy mix compliance or credit including Renewable Portfolio Standards, Renewable Energy Credits, Clean Energy Standards, Installed Tax Credits, Production
[6] Data bar is sum of counts for the number of LSEs that addressed risk in their portfolios. One count for the use of Scenario or Probabilistic Analysis; two counts for those that considered both.

Figure 10. Methods to assess uncertainty by quantitative risk category

7.1 *Demand Risks*

Predicting future demand is a critical step in the creation of an IRP. If demand grows faster than predicted, a number of consequences could occur including rolling blackouts during peak demand periods and high market spot prices for wholesale electricity. Conversely, if demand is lower than anticipated, it is possible the utility will over-invest in the construction of new resources—which could potentially sit idle. Effective DSM reduces demand and can alleviate consequences of over-prediction, but these activities cannot eliminate the risk altogether. Yet, even the successful adoption of DSM is another type of uncertainty considered by LSEs in their long-term planning. Most LSEs run multiple load forecast sensitivity analyses to see how robustly their preferred portfolio responds to a range of consumer demand assumptions.

Technological advancements can have dramatic impacts on the quantity and temporal profile of both demand and supply. For example, Smart Grid[10] and plug-in hybrid electric vehicles (PHEV) are two technologies that have the potential to fundamentally affect future load and the resources that may be selected to meet this demand. Less than one third of the IRPs we reviewed evaluated impacts of Smart Grid technologies in their future demand scenarios, and most of those only alluded to efficiency gains attributed to generic Smart Grid technologies in the future. PHEV and electric vehicles (EV) have long been considered the future of ground transportation (NIST, 1993; Wilkerson et al., 1994). There are a number of studies on the integration of PHEVs/PVs for off-peak charging, load balancing, and general market impacts (e.g., Brown et al., 2010; Hadley and Tsvetkova, 2009; Kim et al., 2012; Pleat, 2012), and most agree that vehicle grid integration will have significant impacts on the electric utility industry. This potential impact has led the PUC of Oregon to require LSEs to address the integration of PHEV/EVs in their RPs (ORPUC, 2012). Most of the LSEs who considered smart grid technology impacts also considered the adoption of EVs in some of their portfolio analyses.

7.2 *Natural gas price risk*

Over the past decade, the U.S. has seen a substantial increase in estimates of conventional and unconventional natural gas supply. Unconventional gas resources, such as coalbed methane and shale gas, have shown substantial growth in the last few years and are rapidly becoming a significant part of the U.S. energy portfolio (Jacoby et al., 2012). There is a considerable amount of uncertainty about how the current natural gas "boom" will affect long-run prices and the future mix of electricity generation capacity across the Western U.S., especially when combined with greenhouse gases (GHG) policies. For example, the Energy Information Administration (EIA) and Wood Mackenzie project that gas consumption will increase if GHGs are regulated; yet, Resources for the Future and MIT project that U.S. gas consumption will decrease if GHGs are regulated (Huntington, 2011).

Figure 11 shows the range of base-case Henry Hub forecasts from the 13 IRPs reporting price forecasts for this hub. The range represents an aggregate of resource planners' mid-value, and not any high or low price sensitivity values. The figure compares the IRP forecast range to the spot price, futures market price, and range of EIA price forecasts. Despite the recent boom in production—which has lowered prices—all forecasts indicate the prices are expected to increase.

[10] Smart Grid generically refers to grid modernization and specifically to the integration of the electrical infrastructure system into a two-way communication network.

Surprisingly, the year the IRP was released played very little role in the range of anticipated prices, since base values from more recent plans span the entire range. This is also a good indication of the increasing level of uncertainty underlying planning decisions.

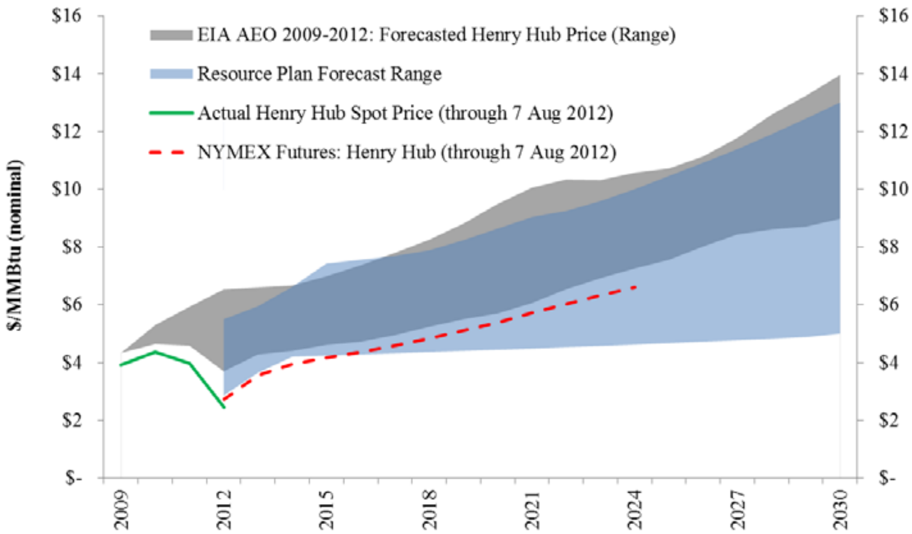


Figure 11. Natural gas spot market prices and anticipated price range

7.3 Environmental or regulatory compliance risks

Environmental regulations have the potential to significantly affect the resource mix of electric utilities. California, for example, recently passed a OTC regulation intended to reduce harmful effects associated with power plant cooling water intake structures on marine and estuarine life (CSWB, 2010). This specific environmental regulation has led (or will lead) to the retirement or complete retrofit of thousands of MWs of natural gas-fired generation capacity along California's coast.

A number of LSEs operate in multiple states which have different RPS requirements. Accordingly, we found that these LSEs evaluated alternatives for complying with the different RPS markets (e.g., Avista, BHP, PacifiCorp, TriState). A few smaller LSEs that operate within a single state evaluated whether meeting Renewable Portfolio Standards or purchasing Renewable Energy Credits (REC) was a more cost effective approach over the long-run (e.g., Chelan). Although, generally, when an LSE operated within a single state, they used only one set of RPS-related constraints. Consequently, far more LSEs are impacted by RPS than is indicated by Figure 10.[11]

A number of federal regulations could affect the operations of electric utilities. Possible regulation of greenhouse gases (GHGs) is perhaps the most widely studied type of legislation by the electric utility industry. Yet, as with natural gas prices, there is great uncertainty about the

[11] It is important to note that utilities typically build out their preferred resources to meet (and in some cases exceed) RPS requirements. We have not attempted to document this in detail among the specific set of plans reviewed, because this specific topic was not the primary focus of our analysis; however, previous work has addressed this topic directly (see Bolinger and Wiser 2005).

impact, timing, and even the likelihood of legislation surrounding carbon. For now, resource planners typically model with either no cost adder for CO_2-equivalent (CO_2e) emissions, or a cost adder that tracks closely with recently proposed pieces of legislation. Older plans typically show that planners expected some form of GHG legislation to pass (i.e., only a few modeled a 'no-carbon-tax' scenario). More recent IRPs use similar CO_2e price pathways as earlier studies, but delay the start dates further into the future—and many LSEs considered the possibility of no GHG legislation over the foreseeable future.

7.4 Risk analysis data availability

PacifiCorp and APS are two examples of plans that contain substantial detail about risk assessment methods and related assumptions. PacifiCorp provided extensive detail on the statistical methods behind their risk analysis simulation. APS provided specific information about the assumptions they used to determine power plant compliance costs. In other IRPs, sensitivities and probabilistic methods and assumptions were clearly reported (e.g., EWEB, PNM, TEP). However, as first described by Eto (1990), there is still a general lack of transparency when describing the algorithms that underlie the capacity expansion and risk analysis models. For most utilities this information was not summarized and required a line-by-line review to extract useful information, and in a few cases, the IRP lacks any technical description of the process.

8. Conclusion

In this study, we reviewed publicly-available planning information for nearly 40 utilities that, in aggregate, are responsible for generating ~90% of the energy in the WECC. We also sent a supplemental survey to resource planning staff to give each LSE an opportunity to update their L&R projections. We conducted this analysis to gain insight into a number of important topics: (1) what Western electric utility planners are assuming about the future growth of electricity demand and supply-side resources; (2) what types of risk Western utilities consider and focus on in their long-term resource planning; and (3) how consistent is the collection and reporting of resource planning-related data across this region.

This analysis found that aggregate energy generation could increase from 857 TWh in 2011 to 1,011 TWh by 2020, which represents an average annual growth rate of ~2%. Unfortunately, not all utilities provided information about expected DSM activities. For those utilities that did report, we anticipate their energy demand and peak power will decrease by 39 TWh (6.4%) and 12,414 GW (8.6%), respectively, from EE activities—and an additional 7,188 MW from DR programs.

We also collected information related to existing and planned power capacity. We found that ~90% of anticipated plant retirements are split between natural gas and coal-fired generators. The most common type of new capacity is natural-gas fired units. A few LSEs anticipate building new (or upgrading) coal-fired generation, but many anticipate growth in wind, solar (mostly PV), biomass, and hydropower over the next few decades. Most of the planned solar capacity is anticipated before 2020, while most of the new wind is expected to come online after 2020. Despite these anticipated changes, thermal generation is expected to remain ~55% of total generation through 2030. However, it is important to note that a significant share of planned generation (~12%) is of an unknown type.

We also evaluated how LSEs are assessing risk to the performance of their resource portfolios. We considered different risk categories and determined which categories receive the most attention from resource planners. Almost all LSEs conducted scenario/sensitivity analyses for natural gas and electricity prices. In addition, uncertainty about future load and the availability of DSM also received considerable attention from most LSEs, as did the availability of lower cost supply-side resources. When we quantify the attention each risk type receives, future load, natural gas prices, and GHG compliance uncertainties dominate LSE risk assessments, followed closely by risk analyses about cost and availability of future wind resources and DSM participation.

One consistent trend we discovered in our review of resource plans is that critical planning assumptions are inconsistently collected and reported by the LSEs. Despite a clear need for new supply and demand-side resources, we found that LSEs rarely reported additions (or improvements) to transmission interconnections, fuel delivery systems, and energy storage facilities. Furthermore, there are numerous examples of resource plans that do not provide sufficient clarity on units of measurement related to important risks (e.g., short tons vs. long tons of GHGs; carbon price vs. CO_2e price; hub vs. delivered natural gas price).

FERC Order 1000 requires that regions begin to coordinate their long-term planning activities (FERC, 2011). We believe that a pair of enabling policies could facilitate regional inter-comparisons and, ultimately, lead to more efficient long-term planning processes across the Western United States and Canada. For example, local/state/regional policymakers should consider: (1) promoting inter-regional electric-gas-transmission planning data collection standards; and (2) supporting additional development of publicly-accessible databases of long-term gas-electric-transmission industry planning assumptions.[12]

Unfortunately, there are no inter-regional planning data standards in place to *collect* information in a consistent manner despite a clear need. The state of Washington requires that LSEs serving at least 25,000 customers must complete a standardized resource planning data template every year (WA, 2008). Data standardization experiences in states like Washington could serve as a useful model for determining inter-regional data collection standards. Encouraging gas-electric-transmission planning entities to identify their most important assumptions—and standardizing the collection of this information (e.g., units of measurement, planning horizons) will clearly improve the long-term coordination of regional planning organizations.

Furthermore, there is a general *lack of access* to publicly-available and consolidated long-term planning assumptions from the natural gas-electric-transmission industries. This lack of consolidation likely leads to inefficient inter-regional planning and increased costs to LSEs and their customers. In addition to requiring gas-electric-transmission entities to report all planning information in a standardized format, we recommend that policymakers continue to support the development of publicly-available systems to collect and distribute a variety of planning assumptions (e.g., load forecasts, supply-side resources, policy assumptions, fuel prices, other cost adders) to stakeholders in a user-friendly format.

Resource planning activities are typically subject to state-level jurisdiction, so the responsibility to standardize processes and improve transparency lies with each public utility commission. However, WECC (or other regional entities, such as the Western Interstate Energy Board) could play an important role coordinating (or convening stakeholders) in the development of common standards and reporting formats. Despite these shortcomings, the general quality and level of detail included in resource plans has increased over time. We anticipate that our recommendations will eventually have direct implications for the ability to explore additional policy-relevant questions in the future (e.g., among comparable LSEs are power plant costs and capacity factors significantly different?). We suspect that emerging policies, like FERC Order 1000, will lead to additional improvements in how effectively utilities—and their customers—plan for the future.

[12] It is important to mention that data elements, occasionally found in utility planning documents, are reported to entities including, but not limited to: the Federal Energy Regulatory Commission, the Department of Energy's Energy Information Administration, and WECC.

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