ARTICLES

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Incomplete Integration: Water, Drought, and Electricity Planning in the West

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INTRODUCTION

The signs of drought were everywhere. Outside Las Vegas, a white "bathtub" ring lined Lake Mead, showing the reservoir's lowest water level since the Hoover Dam was completed in 1930.[1] In Spokane, in the midst of a drought "emergency" declared by Governor Jay Inslee, city officials urged residents to curb water use, while some farmers were unable to irrigate because of low river levels.[2] And in San Diego, restaurant dinner menus contained this disclaimer: "Due to extreme drought, tap water is only served upon request."[3]

In 2015, with drought gripping the region in one of the driest years in history, cities and towns throughout the West felt many other symptoms of decreased water availability. Wildfires ravaged California and parts of the Northwest.[4] Snowpack in the Sierra Nevada range dropped to eighty percent of normal, with snow reserves down to zero in some places as early as May, even though they usually last through the summer.[5] Most ominously, scientists began predicting that by 2100, the Great Plains and Southwest would likely undergo a "megadrought"

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1 Brian Clark Howard, *Worst Drought in 1,000 Years Predicted for American West*, NAT'L. GEOGRAPHIC (Feb. 12, 2015), http://news.nationalgeographic.com/news/2015/02/150212-megadrought-southwest-water-climate-environment.

2 Chad Sokol & Becky Kramer, *Drought Conditions Drive Water Restrictions*, SPOKESMAN-REV. (June 27, 2015), http://www.spokesman.com/stories/2015/jun/27/drought-conditions-drive-water-restrictions.

3 *See* Allie Pape, *California Restaurants and Bars Now Prohibited From Serving Water Sans Request*, S.F. EATER (Mar. 17, 2015), http://sf.eater.com/2015/3/17/8237891/serving-water-california-prohibited-without-request-bars-restaurants/.

4 Matt Ford, *The West's Wildfire Season Gets Worse*, ATLANTIC, http://www.theatlantic.com/national/archive/2015/08/west-wildfire-drought-climate-change/402071/ (last visited Mar. 20, 2016).

5 Eric Holthaus, *California's Snowpack Is Now Zero Percent of Normal*, SLATEST (May 29, 2015), http://www.slate.com/blogs/the_slatest/2015/05/29/california_s_snowpack_now_zero _percent_of_normal_a_worst_case_scenario_for.html; Eric Holthaus, *This Is What a Megadrought Looks Like*, SLATEST (Apr. 3, 2015), http://www.slate.com/blogs/the_slatest/2015/04/03/california_drought_the_state_s_snowpack_is_a_new_record_low_by_far.html. Below average snowpack and above average temperatures during the 2014–2015 winter in Colorado, New Mexico, Utah, and Wyoming suggest that water levels could continue to drop. Caitlyn Kennedy, *Climate Challenge: What Was the Water Level in Lake Mead at the End of July?*, NOAA (Aug. 4, 2015), https://www.climate.gov/news-features/featured-images/climate-challenge-what-was-water-level-lake-mead-end-july.

lasting thirty-five years or longer.[6] Such a drought would create "enough warming and drying to push us past the worst droughts experienced in the region since the medieval era"—making prior megadroughts, like those of the 1100s and 1200s tied to the decline of the Anasazi, "seem like quaint walks through the Garden of Eden."[7]

Of course, drought in the West is nothing new. The region has been so dry for so long, its aridity is the stuff of legend. "[W]hiskey's for drinkin' and water's for fightin'," runs one popular maxim, quickly conveying the reality that Westerners live with daily.[8] Still, drought can have significant—and important—implications for society. Drought directly stresses ecosystems. Often linked to higher temperatures, drought can increase tree mortality and hasten forest-insect outbreaks.[9] Drought presents a severe risk to agriculture, which is particularly important given that the Southwest alone produces over half of the country's high-value specialty crops.[10] Drought also increases the risk of forest fires,[11] which in turn threaten air quality, water quality, public recreation, and urban, suburban, and exurban development.[12] For example, by itself, the 2003 Grand Prix fire in California caused $1.2 billion in damages.[13]

This Article focuses on a different, and often overlooked, impact of drought—its influence on the electricity sector. The connection between water and energy is well-established, and the literature on the topic is growing and important. That scholarship includes, for instance, emphases on and descriptions of the myriad ways that energy and water are connected (typically referred to as the "energy-water" or "water-energy" nexus),[14] assessments and models of the water impacts of

6 Emily Underwood, *Models Predict Longer, Deeper U.S. Droughts*, 347 SCIENCE 707 (2015), http://science.sciencemag.org/content/347/6223/707.full-text.pdf+html.

7 Howard, *supra* note 1.

8 HAL ROTHMAN, NEON METROPOLIS: HOW LAS VEGAS STARTED THE TWENTY-FIRST CENTURY 212 (2002).

9 U.S. GLOBAL CHANGE RESEARCH PROGRAM, CLIMATE CHANGE IMPACTS IN THE UNITED STATES 468 (2014), http://nca2014.globalchange.gov/report/regions/southwest [hereinafter CLIMATE CHANGE IMPACTS].

10 *Id.* at 463.

11 *Id.* at 468.

12 DOUGLAS C. MORTON ET. AL., ASSESSING THE ENVIRONMENTAL, SOCIAL, AND ECONOMIC IMPACTS OF WILDFIRE 16 (2003).

13 CLIMATE CHANGE IMPACTS, *supra* note 9, at 468.

14 *See generally, e.g.*, INT'L ENERGY AGENCY, WATER FOR ENERGY, IS ENERGY BECOMING A THIRSTIER RESOURCE? EXCERPT FROM THE WORLD ENERGY OUTLOOK 2012 1 (2012); U.S. DEP'T OF ENERGY, THE WATER-ENERGY NEXUS: CHALLENGES AND

specific energy technologies,[15] and proposals and suggestions for how to address the difficult tradeoffs that the energy-water nexus presents, especially in light of climate change.[16] Our Article adds to and fills a gap in this scholarships by spotlighting the specific connection between electricity and water,[17] and in particular by evaluating that nexus from the vantage of planning.

OPPORTUNITIES 1 (2014); Michael Blackhurst et al., *Direct and Indirect Water Withdrawals for U.S. Industrial Sectors*, 44 ENVTL. & SCI. TECH. 2126 (2010); Robin Kundis Craig, *Adapting Water Federalism to Climate Change Impacts: Energy Policy, Food Security, and the Allocation of Water Resources*, 5 ENV'T & ENERGY L. & POL'Y J. 183 (2010); Julian Fulton & Heather Cooley, *The Water Footprint of California's Energy System, 1990–2012*, 49 ENVTL. & SCI. TECH. 3314 (2015); P.H. Gleick, *Water and Energy*, 19 ANN. REV. ENERGY ENV'T 267 (1994); Carey W. King et al., *Coherence Between Water and Energy Policies*, 53 NAT. RES. J. 117 (2013); J.E. McMahon & S.K. Price, *Water and Energy Interactions*, 36 ANN. REV. ENVTL. RESOURCES 163 (2011); K.T. Sanders & M.E. Webber, *Evaluating the Energy Consumed for Water Use in the United States*, 7 ENVTL. RES. LETTERS 34 (2012); Alexey Voinov, *The Energy-Water Nexus: Why Should We Care?*, 143 J. CONTEMP. WATER RES. & EDUC. 17 (2009).

15 *See generally, e.g.*, Y.B. Chiu et al., *Water Embodied in Bioethanol in the United States*, 43 ENVTL. & SCI. TECH. 2688 (2009); Robin Kundis Craig, *Hydraulic Fracturing ("Fracking"), Federalism, and the Water-Energy Nexus*, 49 IDAHO L. REV. 241-264 (2013); U.S GENERAL ACCOUNTING OFFICE, ENERGY-WATER NEXUS: A BETTER AND COORDINATED UNDERSTANDING OF WATER RESOURCES COULD HELP MITIGATE THE IMPACTS OF POTENTIAL OIL SHALE DEVELOPMENT (2010), http:/www.gao.gov/products/GAO-11-35; E.A. Grubert, *Can Switching Fuels Save Water? A Life Cycle Quantification of Freshwater Consumption for Texas Coal- and Natural Gas-Fired Electricity*, 7 ENVTL. RES. LETTERS 045801 (2012); M. Wu et al., *Water Consumption in the Production of Ethanol and Petroleum Gasoline*, 44 ENVTL. MGMT. 981 (2009).

16 *See generally, e.g.*, MICHAEL E. WEBBER, THIRST FOR POWER: ENERGY, WATER, AND HUMAN SURVIVAL (2016); Robin Kundis Craig, *Water, Energy, and Technology: The Legal Challenges of Interdependencies and Technological Limits*, *in* ELOISE SCOTFORD ET AL., OXFORD HANDBOOK ON THE LAW AND REGULATION OF TECHNOLOGY (forthcoming 2016); Robin Kundis Craig, *Climate Change Adaptation, the Clean Water Act, and Energy: A Call For Principled Flexibility Regarding "Existing Uses*," 4 GEO. WASH. J. ENERGY & ENVTL. L. 26 (2013); Robin Kundis Craig, *Water Supply, Desalination, Climate Change, and Energy Policy*, 22 PAC. MCGEORGE GLOBAL BUS. & DEV. L.J. 225 (2010).

17 *See also, e.g.*, K. Avery et al., *Water Use for Electricity in the United States: An Analysis of Reported and Calculated Water Use Information for 2008*, 8 ENVTL. RES. LETTERS 015001 (2013); CLEAN AIR TASK FORCE AND THE LAND AND WATER FUND OF THE ROCKIES, THE LAST STRAW: WATER USE BY POWER PLANTS IN THE ARID WEST (2003), http://www.circleofblue.org/waternews/wpcontent/uploads/2010/10/laststraw2009.pdf; U.S. GENERAL ACCOUNTING OFFICE, ENERGY-WATER NEXUS: IMPROVEMENTS TO FEDERAL WATER USE DATA WOULD INCREASE UNDERSTANDING OF TRENDS IN POWER PLANT WATER USE (2009), http://www.gao.gov/products/GAO-10-23; Frank Ackerman & Jeremy Fisher, *Is There a Water–Energy Nexus in Electricity Generation? Long-term Scenarios for the Western United States*, 59 ENERGY POL'Y 235 (2013); Vasilis Fthenakis & Hyung Chul Kim, *Life-Cycle of Water in U.S. Electricity Generation*, 14 RENEWABLE & SUSTAINABLE ENERGY REVS. 2039 (2010); H. Inhaber, *Water Use in Renewable and Conventional Electricity Production*, 26 ENERGY SOURCES 309 (2004); Page Kyle, *Influence of Climate Change Mitigation Technology on Global Demands of Water for*

The electricity-water nexus is important for a variety of reasons. Water is lifeblood. Energy is the backbone of modern society. Yet energy cannot be produced without water, and water use for energy production inevitably creates important tradeoffs by foreclosing other uses—both social and ecological—that water could provide. Moreover, the water-energy nexus is becoming even more important in the face of climate change. Society may shift how it makes energy because of climate change, but climate change also will affect where (and how much) water is available, tying energy and water even more closely together.

Recognizing these connections, this Article assesses how electric utilities in the western United States evaluate water availability for their facilities, and whether and how they plan for drought. To do so, the Article analyzes thirty-three integrated resource plans, including the largest utilities in the West. This analysis shows that a majority of these utilities do not address the availability of water for electricity generation in their plans. Moreover, only a few utilities address the risk of drought, and even fewer present concrete plans to address drought in the event it arises. In short, our analysis shows there is a significant gap between what electric utilities might do to prepare for water shortages and what they are actually doing.

In light of these findings, we suggest four specific ways that utilities—and the states that regulate them—might better integrate water and electricity planning. Any of these options should help make planning more effective and useful; all have limitations. Still, given the likelihood of a megadrought in years to come, and the massive influence that climate change is likely to have on western states, utilities need to begin considering water availability in their planning processes. At a minimum, our analysis of existing integrated resource plans suggests that utilities should include water consumption and drought risk in their assessments of how they will meet electricity demand going forward, in order to facilitate contingency planning for

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Electricity Generation, 13 INT'L J. GREENHOUSE GAS CONTROL 112 (2013); Xiawei Liao, *Water-Energy Nexus: Understanding the Inter-Annual Water Use of Power Plants*, GLOBAL WATER F. (Jan. 11, 2016), http://www.globalwaterforum.org/2016/01/11/power-plants-water-use-and-their-intra-annual-variations/; J. Meldrum et. al., *Life Cycle Water Use for Electricity Generation: A Review and Harmonization of Literature Estimates*, 8 ENVTL. RES. LETTERS 015031 (2013); Jan Mertens, *Water Footprinting of Electricity Generated by Combined Cycle Gas Turbines Using Different Cooling Technologies: A Practitioner's Experience*, 86 J. CLEANER PRODUCTION 201 (2015).

diminished water supplies in the same way they and other stakeholders address other risk factors.

The remainder of this Article proceeds in five parts. Part I provides a general overview of the relationship between water and electricity production, including a discussion of various cooling technologies and information about the West's generation fleet. Part II delves into the phenomenon of drought and its potential impacts on the electricity sector. Part III contains our analysis of thirty-three integrated resource plans from western utilities. Part IV overviews four different possibilities that jurisdictions might pursue to further integrate water and electricity planning. Finally, the Conclusion urges greater integration of water and electricity planning, both by electricity and water planners.

I
WATER AND ELECTRICITY PRODUCTION

Almost every form of electricity production in the United States requires water. For hydroelectricity, this is obvious. Hydropower plants cannot run without sufficient water. Often overlooked in this regard, however, is thermoelectric generation.[18] These facilities also heavily rely on water for cooling. From a water perspective, thermoelectric generation can be divided roughly into two categories. Older facilities built before 1980 withdraw massive amounts of water for cooling but then return the vast majority of this water to the source, only at a higher temperature. Newer facilities built after that year tend to withdraw much less water but consume almost all of what they use.[19]

Cooling, however, is not the only way that thermoelectric facilities rely on water. These facilities are fueled by fossil resources, including coal and natural gas; nuclear power; and biofuels.[20] Each of these fuel sources use water earlier in the production chain, before they are consumed, to make electricity. Fossil fuels require water for the extraction, processing, transportation, and disposal of these resources.[21] Nuclear, too, uses water in the extraction and processing of uranium ore. Likewise, biofuels require irrigation water to grow feedstock

18 U.S. DEP'T OF ENERGY, *supra* note 14, at 1.

19 U.S. DEP'T OF ENERGY, ENERGY DEMANDS ON WATER RESOURCES 9 (2006), http://www.circleofblue.org/wp-content/uploads/2010/09/121-RptToCongress-EWWEIA comments-FINAL2.pdf.

20 CLIMATE CHANGE IMPACTS, *supra* note 9, at 118.

21 U.S. DEP'T OF ENERGY, *supra* note 14, at 1.

crops,[22] making biofuels production the highest water user for primary energy production of all common fuel sources, including conventional gas, coal, and shale gas.[23]

Indeed, the energy-water nexus is so pervasive that essentially no energy resource is untouched by it. Renewables other than biofuels perhaps fare the best, but while some renewable energy sources, including photovoltaic solar power and wind power, require little or no water during operation, even they consume water for manufacture and installation in the front end of the supply chain.[24] Further, depending on the type of technology used, some concentrating solar power facilities can have water needs similar to those for cooling of thermoelectric facilities.[25] And, of course, the type of generation that contributes the most electricity using a renewable resource—hydropower—cannot operate at all without a sufficient water supply.

Direct water use by power plants can be broken into two types: consumption and withdrawals. Distinguishing between the two is important. Consumption refers to the amount of water lost during use by the power plant, typically through evaporation during the cooling process.[26] Withdrawals are the total amount of water a power plant takes in from a water source, recognizing that some or much of that water typically is returned to the source. Of course, return water flows do not possess the same traits as water when originally withdrawn. Return flows from power plants usually have higher temperatures, which potentially can cause harm to ecosystems.[27]

Thermoelectric power plants require water to produce steam, which then spins the turbines that subsequently generate electricity.[28] These

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22 INT'L ENERGY AGENCY, *supra* note 14, at 1.

23 *Id.* at 7. Water and energy are also intertwined beyond the production sphere. The commercial, industrial, and residential sectors use significant amounts of energy to heat and pump water in addition to using significant quantities of water in cooling systems. U.S. DEP'T OF ENERGY, *supra* note 14, at 1.

24 Fthenakis & Kim, *supra* note 17, at 2040.

25 INT'L ENERGY AGENCY, *supra* note 14, at 11; *see also, e.g.*, C.S. Turchi et al., Water Use in Parabolic Trough Power Plants: Summary Results from WorleyParsons' Analyses, NREL/TP-5500-49468 (2010).

26 INT'L ENERGY AGENCY, *supra* note 14, at 11.

27 K. AVERYT ET AL., ENERGY AND WATER IN A WARMING WORLD INITIATIVE, FRESHWATER USE BY U.S. POWER PLANTS: ELECTRICITY'S THIRST FOR A PRECIOUS RESOURCE 3 (2011) [hereinafter FRESHWATER USE].

28 STEVE FLEISCHLI & BECKY HAYAT, NATURAL RES. DEF. COUNCIL, POWER PLANT COOLING AND ASSOCIATED IMPACTS: THE NEED TO MODERNIZE U.S. POWER PLANTS AND

plants withdraw water from nearby lakes, rivers, aquifers, and oceans into condensers that then convert the steam back into water to be reheated to produce more electricity.[29] Depending on the type of cooling technology, the water may be immediately discharged into its source, or it may be used to cool the process several times before discharge.[30] Blowdown,[31] drift,[32] and leakage cause water to be lost during the cooling process, all of which contribute to overall water consumption.[33]

The need for water to cool thermoelectric facilities is critical. Thermoelectric power plants produce nearly ninety percent of electricity in the nation[34] and account for the largest single use of water in the United States—comprising forty-five percent of all water withdrawals, or roughly 161 billion gallons of water per day.[35] In more graphic terms, thermoelectric facilities use enough water to fill up roughly 244,000 Olympic-size swimming pools every day. By contrast, domestic water use accounts for just one percent of all water withdrawals, or 3.6 billion gallons of water per day.[36] Although thermoelectric facilities withdraw such massive amounts of water, they consume on average just three to five percent of the water they withdraw.[37]

PROTECT OUR WATER RESOURCES AND ECOSYSTEMS 2 (2014) [hereinafter POWER PLANT COOLING].

29 *Id.*

30 *Id.* at 3.

31 Over time, the mineral content of water in recirculating cooling systems increases due to evaporative loss. Once the mineral content reaches a certain level, power plants remove the water from the cooling cycle, a process known as blowdown. *Membrane Filtration of Cooling Tower Blowdown*, NEW LOGIC RES., http://www.vsep.com/pdf/Membrane-Treatment-of-Cooling-Tower-Blowdown.pdf (last visited Mar. 25, 2016).

32 In the recirculating system, water returns to a cooling tower to condense before it returning to the generator. Some of the air droplets in the tower get carried out with exhaust air, a process known as drift. *What Is a (Wet, Atmospheric) Cooling Tower?*, COOLING TECH. INS., http://www.cti.org/whatis/coolingtowerdetail.shtml (last visited Mar. 25, 2016).

33 U.S. GEOLOGICAL SURVEY, ESTIMATED USES OF WATER IN THE UNITED STATES IN 2010 at 40 (2014).

34 FRESHWATER USE, *supra* note 27, at 8; Benjamin K. Sovacool & Kelly E. Sovacool, *Identifying Future Electricity–Water Tradeoffs in the United States*, 37 ENERGY POL'Y 2763, 2764 (2009).

35 U.S. GEOLOGICAL SURVEY, *supra* note 33, at 40.

36 *Id.* at 21.

37 *See* FRESHWATER USE, *supra* note 27, at 2 ("In 2008, on average, water-cooled thermoelectric power plants in the United States withdrew 60 billion to 170 billion gallons (180,000 to 530,000 acre-feet) of freshwater from rivers, lakes, streams, and aquifers, and consumed 2.8 billion to 5.9 billion gallons (8,600 to 18,100 acre-feet) of that water.").

Hydroelectric facilities, on the other hand, use the power of flowing water to generate electricity rather than using it for cooling.[38] Hydroelectric facilities store water in a reservoir behind a dam, release the water through a turbine to generate electricity, and then deposit the water through outflow into a river or other water body.[39] Because the water that flows through the turbines into the outflow is immediately available for other uses, those flows typically are not considered water withdrawals or consumption.[40] However, because reservoirs expand the surface area of the rivers penned up behind the dam, hydroelectric generation increases evaporation and thus overall water consumption.[41] Hydroelectric facilities consume an average of eighteen gallons of water per kilowatt-hour of energy produced due to evaporative loss, even though the facilities do not technically withdraw water.[42] By contrast, thermoelectric facilities consume an average of roughly one-half gallon of water due to evaporative loss per kilowatt-hour of energy produced.[43]

Thus, electricity production in the United States depends heavily on water supplies that must be both sufficient and sustainable. The water must be sufficient because without it hydroelectric facilities cannot run at all and thermoelectric facilities cannot cool, preventing reliable operation. Water supplies also must be sustainable. Electricity infrastructure is long-lasting, with plants typically operating decades or longer. Water supplies to help such facilities run, then, cannot be itinerant or fleeting. They must be reliable and as temporally durable as the electricity facilities themselves. This is particularly true in the West, where aridity is already prevalent and likely to become only worse with climate change.

A. Electricity Production and Cooling Technologies

Thermoelectric generation facilities use huge amounts of water. Overall, the nation's thermoelectric generation fleet averages three

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38 P. TORCELLINI, N. LONG & R. JUDKOFF, NAT'L RENEWABLE ENERGY LABORATORY, CONSUMPTIVE WATER USE FOR U.S. POWER PRODUCTION 2 (2003).

39 *How Hydropower Works*, ENERGY.GOV, http://energy.gov/eere/water/how-hydropower-works (last visited Mar. 25, 2016).

40 TORCELLINI ET AL., *supra* note 38, at 2.

41 *Id.* (demonstrating that the presence of Glen Canyon Reservoir resulted in four percent more evaporation per year than would occur in a free-running river).

42 *Id.* at iv.

43 *Id.*

times as much water use for cooling each minute than passes through Niagara Falls in that same period of time.[44] Facility by facility, the precise amount of water needed for cooling depends on the type of technology used, because each cooling method varies in its water efficiency.

Thermoelectric plants utilize four different types of cooling technology: (1) once-through systems; (2) recirculating, or "closed-cycle," systems; (3) dry-cooling systems; and (4) hybrid systems that combine wet and dry-cooling technology.[45] Nationally, coal-burning facilities rely evenly on once-through and recirculating systems—about fifty percent in each category—and almost not at all on dry-cooling systems.[46] Roughly sixty-three percent of natural gas-burning facilities rely on recirculating systems, thirty percent use once-through systems, and about eight percent use dry-cooling systems.[47] Nuclear generation, like coal-burning facilities, relies equally on once-through and recirculating systems.[48] No nuclear facilities use dry-cooling technology.[49]

Once-through systems typically withdraw water from freshwater sources.[50] These systems function by taking water from the external source, using that water to cool the steam used to produce electricity in a condenser, and then discharging the water back to the original external source at a higher temperature.[51] Once-through systems do not recycle water and thus require the most water of any cooling technology.[52] Their heavy reliance on water makes plants that utilize once-through cooling technology particularly vulnerable during times of drought.[53] Regulations now strongly disfavor the use of once-through cooling technologies at newly constructed power plants.[54]

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44 FRESHWATER USE, *supra* note 27, at 1.

45 FRESHWATER USE, *supra* note 27, at 8.

46 Less than one percent of facilities currently use this technology. *See Many Newer Power Plants Have Cooling Systems That Reuse Water*, U.S. ENERGY INFO. ADMIN. (Feb. 11, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=14971.

47 *Id.*

48 *Id.*

49 *Id.*

50 U.S. GEOLOGICAL SURVEY, *supra* note 33, at 40.

51 POWER PLANT COOLING, *supra* note 28, at 3.

52 *See id.*

53 *Id.*

54 National Pollutant Discharge Elimination System—Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend

Recirculation systems, also known as closed-cycle cooling systems, work similarly to once-through systems but offer better water efficiency, at least in terms of withdrawals. Although recirculating systems consume up to eighty percent more water than once-through cooling systems, they withdraw ninety-five percent less water over time.[55] Moreover, these systems can withdraw from both freshwater and saline water sources.[56] In closed-cycle systems, once water is withdrawn from the external source, it is used as it is in a once-through system to cool the steam used for generation.[57] At that point, however, the technologies depart. Rather than immediately discharging the water back to the environment after use as the once-through system would, the closed-cycle system first condenses the water and recirculates it, typically multiple times.[58] Because closed-cycle systems use the same water source repeatedly, they cut water withdrawals by about 95 percent when compared to once-through systems.[59] However, because the water is exposed to constant heat, more water is lost through evaporation than in a once-through system.[60]

Dry cooling systems rely on ambient air and use virtually no water.[61] Consequently, these systems operate most optimally in cooler air and are considerably less efficient in higher air temperatures.[62] Natural gas-burning facilities are the preeminent users of dry-cooling technology in the United States.[63] Plants utilizing dry cooling technology have an estimated 2 percent average annual generation output loss because the comparative inefficiency of dry cooling, which depends on ambient air temperature and overall humidity.[64] Dry cooling systems also present significantly higher capital costs than wet cooling systems. Dry cooling systems cost an average of $30 million, while wet cooling equipment

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Requirements at Phase I Facilities, 79 Fed. Reg. 48,300 (Aug. 15, 2014) (codified in various sections of 40 C.F.R pts. 122 & 125).

55 POWER PLANT COOLING, *supra* note 28, at 3 (citing ERIK MIELKE ET AL., WATER CONSUMPTION OF ENERGY RESOURCE EXTRACTION, PROCESSING, AND CONVERSION 33 (2010)).

56 U.S. GEOLOGICAL SURVEY, *supra* note 33, at 40.

57 POWER PLANT COOLING, *supra* note 28, at 3.

58 *See id.*

59 *See id.*

60 *Id.*

61 *Id.*

62 FRESHWATER USE, *supra* note 27, at 34.

63 U.S. ENERGY INFO. ADMIN., *supra* note 46.

64 POWER PLANT COOLING, *supra* note 28, at 3.

costs approximately $7 million.[65] However, dry cooling gives power plants greater flexibility in location by freeing facilities from needing to be near a large body of water.

Finally, hybrid cooling systems combine wet cooling (either once-through or recirculating) with dry cooling systems. Hybrid systems reduce water use compared to traditional wet cooling systems by up to 50 percent.[66] These plants are typically designed to operate as a dry-cooling facility in the winter months, with supplemented wet cooling in the drier, hotter summer months.[67]

Table 1. Water withdrawals and consumption by cooling technology[68]

Cooling technology	Water withdrawals	Water consumption
Once-through	20,000–50,000 gal/MWh	100–317 gal/MWh
Recirculating	500–1,200 gal/MWh	480–1,100 gal/MWh
Dry	0 gal/MWh	0 gal/MWh
Hybrid	Varies	Varies

B. Electricity Production in the West

As is true throughout the country, states in the West use a variety of technologies to produce electricity. These include renewable and nonrenewable resources. However, natural gas-fired generation is the predominant source of thermoelectric energy in the West, followed by

65 Stacy Tellinghuisen, Western Resource Advocates, Every Drop Counts: Valuing the Water Used to Generate Electricity 48 (2011).

66 Sean Bushart, *Advanced Cooling Technologies for Water Savings at Coal-Fired Power Plants*, CORNERSTONE (Apr. 11, 2014), http://cornerstonemag.net/advanced-cooling-technologies-for-water-savings-at-coal-fired-power-plants/.

67 *See id.*

68 *See* POWER PLANT COOLING, *supra* note 28, at 4.

coal-burning plants.[69] Arizona boasts the nation's largest nuclear power plant.[70]

Table 2. National versus West electricity generation by type[71]

Generation type	National	Western U.S.
Thermoelectric	86%	77%
Coal	33%	22%
Natural Gas	33%	49%
Nuclear	20%	6%
Petroleum	1%	<1%
Hydroelectric	6%	16%
Other Renewables	7%	7%

Overall, thermoelectric plants produce the majority of energy in the West, consistent with nationwide trends.[72] Nuclear plants use the most water of any thermoelectric production process—roughly 43 gallons

69 WESTERN RESOURCE ADVOCATES, A POWERFUL THIRST: MANAGING THE ELECTRICITY SECTOR'S WATER NEEDS AND THE RISK OF DROUGHT 3 (2012) [hereinafter A POWERFUL THIRST].

70 *State Profile and Energy Estimates: Arizona*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/state/?sid=AZ (last updated Dec. 17, 2015).

71 *See What is U.S. Electricity Generation by Energy Source*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3 (last updated Apr. 1, 2016); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Arizona*, http://www.eia.gov/state/?sid=AZ#tabs-4 (last updated Dec. 17, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: California*, http://www.eia.gov/state/?sid=CA#tabs-4 (last updated Dec. 17, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Colorado*, http://www.eia.gov/state/?sid=CO#tabs-4 (last updated Dec. 17, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Idaho*, http://www.eia.gov/state/?sid=ID#tabs-4 (last updated Nov. 19, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Montana*, http://www.eia.gov/state/?sid=MT#tabs-4 (last updated Nov. 19, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Nevada*, http://www.eia.gov/state/?sid=NV#tabs-4 (last updated Nov. 19, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: New Mexico*, http://www.eia.gov/state/?sid=NM#tabs-4 (last updated Dec. 17, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Oregon*, http://www.eia.gov/state/?sid=OR#tabs-4 (last updated Oct. 15, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Utah*, http://www.eia.gov/state/?sid=UT#tabs-4 (last updated Nov. 19, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Washington*, http://www.eia.gov/state/?sid=WA#tabs-4 (last updated Oct. 15, 2015); U.S. ENERGY INFO. ADMIN., *State Profile and Energy Estimates: Wyoming*, http://www.eia.gov/state/?sid=WY (last updated Dec. 17, 2015). The additional one percent for thermoelectric (representing eighty-six percent rather than eighty-five percent) is attributable to oil combustion. That is not listed separately in the table because oil is used so little throughout the United States for electricity production.

72 *See* A POWERFUL THIRST, *supra* note 69, at 2.

per kilowatt-hour of electricity produced.[73] Coal-burning plants use roughly 36 gallons per kilowatt-hour of electricity produced.[74] Natural gas plants use approximately 14 gallons per kilowatt-hour of electricity generated.[75]

As shown in Table 2, seventy-seven percent of electricity in the West comes from thermal facilities, whereas eighty-six percent of electricity is produced thermally on a national basis. This breaks down as follows: natural gas burning facilities generate the most electricity in the West—forty-nine percent.[76] Coal-burning facilities follow with twenty-two percent of generation.[77] Nuclear facilities produce the lowest amount of thermoelectric power in the West, at six percent of total generation.[78]

On a state-by-state basis, coal-fired plants account for the largest portion of generation in Arizona, Colorado, Montana, New Mexico, Utah, and Wyoming.[79] Natural gas generation makes up a significant portion of electricity production in California, Montana, Nevada, New Mexico, Oregon, Utah, and Wyoming.[80] Washington relies predominantly on hydroelectric generation.[81] In the West, only Arizona generates substantial amounts of electricity from nuclear power.[82] Accordingly, each of these states is particularly sensitive to water shortages.

Table 3. Water consumption by generation type[83]

Generation type	Water consumption (gallon/kWh)
Nuclear	43
Coal	36
Natural Gas	14

73 Sovacool & Sovacool, *supra* note 34, at 2764.

74 *Id.*

75 *Id.*

76 *See State Profile and Energy Estimates*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/state/ (last visited May 08, 2016).

77 *Id.*

78 *Id.*

79 *Id.*

80 *Id.*

81 *Id.*

82 *See State Profile and Energy Estimates: Arizona*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/state/?sid=AZ (last updated Dec. 17, 2015).

83 *See* Sovacool & Sovacool, *supra* note 34, at 2764.

Thermoelectric facilities in the West predominately use recirculating and dry cooling systems.[84] This stands in contrast to national trends, as many eastern states often use once-through cooling systems, in part because water is more abundant in that region of the country. In 2012, recirculating systems made up 53% of reported cooling technologies nationwide; once-through cooling comprised 43%; dry cooling accounted for 3%; and hybrid cooling systems made up 0.3%.[85] However, a large geographic area of southern California receives electricity from plants utilizing once-through cooling systems, which require markedly greater water withdrawals.[86] Table 4 illustrates the amount of water withdrawn by power plants in the West, shown by the type of cooling technology used.

Once-through cooling is more common on the East coast compared to the West.[87] Consequently, power plant water withdrawals east of the Mississippi tend to be much higher than in the West.[88] This region also produces more electricity compared to the West, driving withdrawal rates even higher.[89] The western region is predominantly home to recirculating and dry cooling systems, although dry-cooled facilities generated only four percent of the East's electricity.[90] Table 4 summarizes water withdrawals in western states, separated by once-through and recirculating cooling systems.[91]

84 FRESHWATER USE, *supra* note 27, at 14.

85 U.S. ENERGY INFO. ADMIN., *supra* note 46.

86 *Id.*

87 FRESHWATER USE, *supra* note 27, at 14.

88 *Id.*

89 *Id.*

90 *Id.*

91 U.S. GEOLOGICAL SURVEY, *supra* note 33, at 43.

Table 4. Cooling technologies in the West

State	Once-through (million gallons/day)	Recirculating (million gallons/day)
Arizona	0	104
California	6,490	114
Colorado	17.7	59.3
Idaho	0	0.88
Montana	122	28.8
Nevada	0	32.6
New Mexico	0	51.9
Oregon	0	12.7
Utah	0	80.6
Washington	0	37.9
Wyoming	0	63.4

Nearly every state in the West relies on hydroelectric power for at least a portion of its generation portfolio.[92] In Idaho, Oregon, and Washington, hydroelectric generation is the leading source of electricity production.[93] Hydroelectric generation accounts for forty-three percent of total electricity generation in Idaho, fifty percent in Oregon, and sixty-one percent in Washington.[94] These states are particularly sensitive to water shortages because they need water for hydroelectric production while also relying on coal- and natural gas-fired power.[95]

II
DROUGHT AND ELECTRICITY PRODUCTION

Drought places a heavy burden on both thermoelectric and hydroelectric power plants. For thermoelectric facilities, drought's impact is a double whammy. First, drought can drive down plant efficiency, because the higher ambient (air and water) temperatures often associated with drought make generators more difficult to cool. Second, plant reliability also reduces during drought because raised temperatures result in a less effective cooling process, which can force plants to shut down until water temperatures lower to an effective

92 *State Profile and Energy Estimates*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/state/ (last visited May 08, 2016).

93 *Id.*

94 *Id.*

95 *Id.*

level.[96] For hydroelectric facilities, drought can directly influence electricity output because these plants depend on seasonal cycles of precipitation and snowmelt to provide a consistent source of energy throughout the year.[97]

The effects of drought on energy production risks are not just theoretical. Recently, instances of drought affecting electricity production have been documented across the nation. In 2012, thermoelectricity plants were forced to cut back output across the Midwest and East Coast due to drought.[98] One plant ceased operation because prolonged drought conditions exposed the plant's intake pipes to dry ground.[99] Another plant, in Illinois, shut down when low water levels killed a large number of fish, which blocked the plant's intake pipes.[100] In August 2012, the Millstone Power Station in Waterford, Connecticut, shut down one of its two nuclear reactors because of high water temperatures.[101] Due to rising sea temperatures, the water the plant drew from the Long Island Sound was too warm to cool equipment outside the reactor core.[102]

Likewise, in 2007, drought conditions in the Southeast forced both nuclear and coal-fired power plants in the Tennessee Valley Authority system to shut down or significantly curtail operations.[103] Intake water exceeded 90°F for twenty-four hours, which made cooling the facilities impossible.[104] Further, drought conditions along the Mississippi River in 2006 curtailed power production in Illinois and Minnesota.[105] In fact, in 2012, U.S. nuclear power production hit its all-time lowest seasonal level in nine years as drought and extreme heat forced plants from Ohio to Vermont to curtail output.[106]

This Part briefly surveys the likelihood of drought in the American West in coming years, driven in part by climate change. It then

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96 Sovacool & Sovacool, *supra* note 34, at 2764.

97 CLIMATE CHANGE IMPACTS, *supra* note 9, at 118.

98 U.S. DEP'T OF ENERGY, IMPACTS OF LONG-TERM DROUGHT ON POWER SYSTEMS IN THE U.S. SOUTHWEST 6 (2012) [hereinafter IMPACTS OF LONG-TERM DROUGHT].

99 *Id.*

100 *Id.*

101 *Id.* at 11.

102 *Id.*

103 *Id.* at 6.

104 *Id.*

105 *Id.*

106 POWER PLANT COOLING, *supra* note 28, at 7. Likewise, a drought in France in 2003 caused nuclear plants to reduce production by up to fifteen percent for five weeks. *Id.* at 6.

identifies how these reductions in water availability may impact electricity production.

A. Climate Change, Drought, and the West

The West in general, including the Intermountain West and particularly the Southwest, is already the driest region in the country.[107] This makes it especially vulnerable to water shortages and drought, simply because there is less flexibility for the region to respond when water resources diminish or disappear.[108] Indeed, drought has affected the American West for many of the past fifteen years, and scientists predict that drought will continue to plague the region through the end of this century.[109] Already, moderate to extreme drought has afflicted much of Arizona, California, Oregon, Nevada, Utah, and Washington over the past year,[110] leading California's governor to declare a state of emergency in 2014 and Washington's governor to declare a statewide drought in 2015.[111] That, however, was only the beginning. In 2015, Oregon's governor, Kate Brown, declared a state of emergency in eight counties due to water shortages—and Idaho's governor, Butch Otter, did the same in five counties.[112]

Thus, the threat of increased, persistent drought in the West casts a shadow over the future of electricity production in the region. As water availability decreases, the risks posed to the electricity system rise, particularly under the specter of climate change.

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107 CLIMATE CHANGE IMPACTS, *supra* note 9, at 463; *see also Southwest*, CLIMATE NEXUS (May 2, 2016), http://climatenexus.org/southwest.

108 CLIMATE CHANGE IMPACTS, *supra* note 9, at 463.

109 PETER W. CULP, ROBERT GLENNON & GARY LIBECAP, SHOPPING FOR WATER: HOW THE MARKET CAN MITIGATE WATER SHORTAGES IN THE AMERICAN WEST 9 (2014).

110 NAT'L OCEANIC AND ATMOSPHERIC ADMIN., PALMER DROUGHT SEVERITY INDEX JULY 2014–2015, http://www.ncdc.noaa.gov/temp-and-precip/drought/historical-palmers/psi/201407-201507 (based on the Palmer Drought Index); *see also* NAT'L OCEANIC AND ATMOSPHERIC ADMIN., NORTH AMERICAN DROUGHT MONITOR JUNE 2015, http://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps.

111 Office of Governor Edmund G. Brown, *Governor Brown Declares Drought State of Emergency*, CA.GOV (1-17-2014), https://www.gov.ca.gov/news.php?id=18368; Washington Governor Jay Inslee, *Governor declares statewide drought emergency*, (May 15, 2015), http://www.governor.wa.gov/news-media/governor-declares-statewide-drought-emergency.

112 Exec. Order No. 15-05 (2015) (in Deschutes, Grant, Jackson, Josephine, Lane, Morrow, Umatilla, and Wasco counties); Frankie Barnhill, *Drought Emergency Declared In 5 Idaho Counties . . . So Far*, BOISE STATE PUB. RADIO, Apr. 29, 2015, http://boisestatepublicradio.org/post/drought-emergency-declared-5-idaho-countiesso-far (in Fremont, Blaine, Lincoln, Butte, and Custer counties).

Scientists predict that climate change will cause temperatures in the West to increase, which will in turn exacerbate both the frequency and severity of droughts in the region. These effects, combined with diminishing groundwater reserves and continuing population growth, pose a large risk for the West as a whole.[113] The waters of the Colorado River Basin—which includes much of Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming, as well as parts of Mexico—currently support over forty million people in the United States.[114] Yet the basin is already overtaxed. The average demand for Colorado River Basin water has exceeded supply every year since 2003, and the river was significantly over-allocated based on historical climate record to begin with. Drought, then, can only make the situation worse.[115]

Increased temperatures in the West will hasten drought, both because they are likely to reduce the total amount of precipitation by shifting weather patterns and because they will reduce snowpack, thus limiting the way the region naturally stores water for warmer months.[116] Temperatures in the West have steadily risen over the past fifty years.[117] By the end of the century, temperatures are projected to rise by 5.5 to 9.5°F,[118] although sufficient global efforts to mitigate climate change could limit temperature increases in the West to 3.5 to 5.5°F.[119]

Along with higher average temperatures from climate change, scientists predict that mean precipitation will decrease in mid-latitude dry regions of the United States, which includes the American West.[120] Winter and spring precipitation in the West is projected to decrease through the end of the century.[121] Moreover, less late-winter precipitation is likely to fall as snow in this region, which means that,

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113 The population of the West is expected to increase to 94 million by 2050—a 68% increase from today's population of 56 million people. CLIMATE CHANGE IMPACTS, *supra* note 9, at 463.

114 CULP ET AL., *supra* note 109, at 6.

115 *Id.* at 8–9.

116 CLIMATE CHANGE IMPACTS, *supra* note 9, at 464.

117 *Id.*

118 *Id.*

119 *Id.*

120 INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2014 SYNTHESIS REPORT 60 (2015), http://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_FINAL_full_wcover.pdf.

121 CLIMATE CHANGE IMPACTS, *supra* note 9, at 465.

combined with earlier snowmelt, yearly stream flow will come earlier.[122] In turn, earlier stream flows can result in shortages later in the year—demonstrated by diminished stream flows of up to thirty-seven percent in the Sacramento-San Joaquin, Colorado, Rio Grande, and Great Basin basins from 2001 to 2010 compared to twentieth century levels.[123]

All this draws a very bleak picture for the West's future. While demand for Colorado River Basin water already has exceeded supply for over a decade, studies suggest an increased imbalance of up to twenty percent more by 2060.[124] To compensate for current water shortages, the West is tapping into groundwater reserves at alarming rates. Freshwater reserves declined by fifty-three million acre-feet from 2004 to 2013 alone: enough water to fill the Great Salt Lake three-and-a-half times.[125] This trend is only likely to exacerbate if the frequency and magnitude of drought increases with climate change in years to come.

B. Drought and Electricity Production in the West

Climate change and drought present three separate—but intertwined—problems for the West's electricity system. First, and most directly, climate change and drought are likely to reduce the amount of overall available electricity generation. Both the short-term and extended effects of drought conditions have an immediate effect on generation capacity. A temporary heat spike can warm cooling water and consequently reduce cooling efficiency, which in turn reduces overall generation output.[126] Diminished water availability in long-term drought conditions can thus reduce generation capacity for extended periods of time.[127] In addition, long-term drought conditions will place more strain on production components, which can lead to increased vulnerability and, eventually, cascading electricity system failures.[128]

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122 *Id.*

123 *Id.*

124 CULP ET AL., *supra* note 109, at 9.

125 *Id.*

126 *See* IMPACTS OF LONG-TERM DROUGHT, *supra* note 98, at 6.

127 *Id.*

128 *Id.* As an example of the possible impact of drought, the National Energy Technology Laboratory conducted a 2009 study examining the potential effects of persistent drought on the western electricity generation. The study modeled severe drought conditions spanning a period of ten years—from 2010 to 2020—and predicted that electricity generated from coal would drop eight percent in 2010, 6.6 percent in 2015, and 3.7 percent in 2020 due to cooling technology vulnerability. Under drought conditions, natural gas generation compensated for

Second, reduced precipitation, less snowpack, and faster snowmelt associated with climate change will reduce hydropower production in many western states. Severe drought conditions could cause reductions in hydroelectric generation of up to thirty percent.[129] As noted, hydropower leads all electricity production in Idaho, Montana, Oregon, and Washington.[130] Likewise, Arizona, California, Colorado, Nevada, Utah, and Wyoming rely on hydropower for at least a portion of their electricity.[131] Drought conditions in California have already diminished the state's typical hydroelectric output by nearly half of pre-drought averages.[132] As reservoirs continue to lower, the force of water to turn dams' turbines reduces. If a reservoir lowers to its "dead pool" level—the level at which water would not spin the turbines at all—a hydroelectric facility connected to a reservoir becomes defunct.[133] Drought presents this risk.

Third, while drought diminishes available electric generation, higher temperatures are likely to increase electricity demand. It is self-evident that electricity demand is highest on hot days, when commercial and residential consumers increase consumption, most heavily for cooling. As temperatures increase, this phenomenon will only be amplified.[134] The number of cooling degree days where temperatures rise above 65°F are expected to increase over the 2041–2070 period by an average of 66 percent across the West compared to 1971–2000 levels.[135] As a result, primary energy demand could increase by up to eleven percent.[136] Accordingly, to meet the demand for peak electricity,

diminished coal generation. However, coal-fired production picked up by 2020 because of increased installation of cooling technologies less vulnerable to drought in coal facilities. NAT'L ENERGY TECHNOLOGY LABORATORY, AN ANALYSIS OF THE EFFECTS OF DROUGHT CONDITIONS ON ELECTRIC POWER GENERATION IN THE WESTERN UNITED STATES 1, 18−21 (2009) [hereinafter EFFECTS OF DROUGHT CONDITIONS].

129 *Id.*

130 *See generally State Profile and Energy Estimates*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/state/ (last visited May 08, 2016).

131 *Id.*

132 Jonathan Thompson, *Mapping Drought's Impact on Electricity Generation*, HIGH COUNTRY NEWS (July 7, 2015), https://www.hcn.org/articles/hydropower-california-drought-water-energy-electricity-dams.

133 *Id.*

134 CLIMATE CHANGE IMPACTS, *supra* note 9, at 116.

135 *Id.*

136 *Id.* at 117.

utilities will need to construct additional generation and distribution facilities because current capacity simply will not be adequate.[137]

Diminished generation capacity, reduced hydroelectric generation, and increased electric demand thus present three distinct but interrelated challenges to the electricity sector. Each, on its own, will be difficult to address. However, the three together may create a particularly significant quandary. Indeed, already, California has incurred an estimated $2 billion in electricity costs—a burden borne by ratepayers—from diminished hydroelectric generation caused by drought.[138] The National Energy Technology Laboratory has predicted that production costs could rise by $4.5 billion as a result of persistent long-term drought conditions in the West.[139] Given that a core objective of the electricity system in the United States is to ensure the provision of reliable energy at low-cost rates for consumers,[140] the risks created by drought strike at the heart of the system's function. Moreover, in a world altered by climate change, California will not be alone. States across the West could see price increases, supply destabilizations, and other problems that significantly tax the electric grid during drought conditions.

III
PLANNING AND ELECTRICITY PRODUCTION

The long-term risks posed by climate change and drought highlight the need for careful planning by western electric utilities. Of course, utilities long have prided in themselves in their ability to plan, even if those plans have not always panned out, such as when utilities collectively overbuilt generation capacity in the decades after World War II, or when many utilities abandoned their earlier decisions to construct nuclear plants as the costs of that technology and public opposition to it rose. Nonetheless, planning is deeply engrained within the electric utility industry culture.

A key form of planning used today by electric utilities is the "integrated resource plan," or "IRP." Offspring of the 1970s energy

137 *Id.*

138 Tara Lohan, *Drought Costs Californians an Extra $2 Billion in Electricity Expenses*, HUFFPOST SCIENCE (Feb. 19, 2016), http://www.huffingtonpost.com/entry/california-drought-electricity-bill_us_56c79cffe4b0ec6725e2b19a.

139 EFFECTS OF DROUGHT CONDITIONS, *supra* note 128 at 23.

140 *See, e.g.*, 16 U.S.C. 824(d) (2012); Joseph P. Tomain, *The Dominant Model of United States Energy Policy*, 61 U. COLO. L. REV. 355 (1990).

crises, IRPs forecast future demand for electricity and then seek to match various resources, including generation and demand reduction, to those demand projections, on a lowest-cost basis.[141] IRPs are quite prevalent in the United States. As of 2011, twenty-seven states had IRP requirements, including every state west of the Continental Divide save Alaska and California.[142]

Because IRPs aim to take a holistic approach to electricity system planning, they are the natural place where utilities might assess the potential impact of drought and climate change on available generation resources. Indeed, by their very nature, IRPs evaluate a range of possibilities for meeting future electricity demand, so it would only seem logical for these plans to also appraise how a key constraint on electricity production—water availability—might play out in different situations.

Accordingly, to assess the extent to which utilities plan for water availability and the potential risks of drought, we conducted an original analysis of thirty-three IRPs. What we found was telling. Only thirty-nine percent of western utilities expressly take water consumption needs into account when planning for future electricity demand and supply in their IRPs, and only one-tenth plan for drought.[143] Thus, in the shadow of a future that may be much drier than the already arid world in which utilities operate, there appears to be much room for improvement in how utilities plan for water and drought.

This Part presents the results of our analysis of western utility IRPs. First, however, it briefly overviews how IRPs function.

A. Integrated Resource Planning

Integrated resource planning arose from the energy crises of the 1970s. California was the first state to mandate a form of planning akin to what we now know as an IRP, in its the Warren-Alquist State Energy

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141 Mark Bolinger & Ryan Wiser, *Utility Integrated Resource Planning, An Emerging Driver of New Renewable Generation in the Western United States*, 6 REFOCUS 20, 20 (2005).

142 RACHEL WILSON & PAUL PETERSON, A BRIEF SURVEY OF STATE INTEGRATED RESOURCE PLANNING RULES AND REQUIREMENTS 11 (2011), http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf.

143 *See infra* Part III.B.

Resources Conservation and Development Act of 1975.[144] Eight years later, in 1983, Nevada followed California's lead and became "the first state to adopt through its legislature comprehensive and detailed integrated resource planning regulations."[145] By the early 1990s, over half of all states required integrated resource planning of some kind, although some requirements were legislative and some were instituted by state public utility commissions.[146]

The path since then has been more tangled. In the early 1990s, the Energy Policy Act of 1992 mandated that state public service commissions consider implementing IRP requirements.[147] However, in the wake of the ensuing restructuring and move to competition in the electricity industry in the late 1990s and early 2000s, "many states that had integrated resource planning requirements either repealed them with restructuring laws, or simply began to ignore them."[148] Then, some states that repealed their IRP requirements later replaced them with new rules for long-term generation resource procurement plans.[149] Today, the vast majority of the nation—all states but Alaska and eleven others scattered through the Midwest, South, and Northeast—either have IRP mandates or long-term resource procurement planning requirements.[150] Of this group, more than two-thirds employ IRP requirements rather than general resource procurement mandates.[151] The net effect is that integrated resource planning is a staple in the electricity industry throughout the country, and even where IRP is not in place, a close cousin of it often is.

Understanding the basics of IRP is relatively straightforward, even if implementing it is not. In broad strokes, electric utilities use integrated resource plans as a long-term forecasting and development mechanism to determine the least-cost, lowest-risk method for shaping

144 CAL. PUB. RES. CODE §§ 25000−25980 (West 1992); Scott F. Bertschi, *Integrated Resource Planning and Demand-Side Management in Electric Utility Regulation: Public Utility Panacea or a Waste of Energy?*, 43 EMORY L.J. 815, 836 (1994).

145 Bertschi, *supra* note 144, at 836; *see* NEV. REV. STAT. ANN. §§ 704.741, 704.746, 704.751 (2015).

146 *See* Lesley K. McAllister, *Adaptive Mitigation in the Electric Power Sector*, 2011 B.Y.U. L. REV. 2115, 2152 (2011).

147 Energy Policy Act of 1992, 42 U.S.C. §§ 13201−13574 (2012); *see* Clinton A. Vince et al., *Integrated Resource Planning: The Case for Exporting Comprehensive Energy Planning to the Developing World*, 25 CASE W. RES. J. INT'L L. 371 (1993).

148 WILSON & PETERSON, *supra* note 142, at 5.

149 *See id*.

150 *See id*. at 14.

151 *See id*.

their generation portfolios. An IRP thus establishes a plan to meet projected peak electricity demand and analyzes supply- and demand-side resources over a specified length of time to determine the optimal way to meet that demand.[152] Planning periods are long-range and typically span ten to twenty years, with a twenty-year planning horizon most common.[153] Most often, utilities create the initial plan and submit it to their state regulatory body, such as a public utility commission or public service commission. Depending on the state, the commission may then simply acknowledge receipt of the plan as filed, or instead, may review, comment on, and accept or reject the plan, although in some states, the regulatory body creates an overall statewide plan.[154] Typically, utilities are required to update their plans periodically, often every two to five years, with two years being most common.[155]

Although requirements vary from state to state, the IRP process typically includes five steps. First, utilities develop peak demand or "load" forecasts over the planning period using historical trends and future projections.[156] Next, utilities assess how these forecasts compare to existing and committed generation resources, and analyze whether their current portfolios can satisfy demand expectations.[157] Then, after identifying any potential deficiencies, the utility evaluates different possible resource portfolios that could be used to meet customer demand.[158] Once it has done that, the utility analyzes a chosen candidate portfolio under an array of future scenarios, including both high and low demand situations.[159] This step of the analysis often includes risk assessment. Finally, the utility selects the preferred

152 RACHEL WILSON & BRUCE BIEWALD, REGULATORY ASSISTANCE PROJECT, BEST PRACTICES IN ELECTRIC UTILITY INTEGRATED RESOURCE PLANNING 4 (2013) [hereinafter BEST PRACTICES]. Notably, however, most modeling software used in IRP focuses on determining the "optimal" portfolio given a set of assumptions about the future, not an "ideal" portfolio to optimize for a variety of objectives that a regulatory authority might wish to pursue. This has been a point of criticism by some. *See, e.g.*, David Magnus Boonin, *Utility Scenario Planning: Always 'Acceptable' vs. the 'Optimal' Solution*, ElectricityPolicy.com, http://www.electricitypolicy.com/Boonin-3-17-11-cc-rom 4.pdf.

153 *Id.* at 6; WILSON & PETERSON, *supra* note 142, at 7.

154 Bertschi, *supra* note 144, at 835; McAllister, *supra* note 146, at 2152; *see also* WILSON & PETERSON, *supra* note 142, at 3–4.

155 WILSON & PETERSON, *supra* note 142, at 8.

156 Bolinger & Wiser, *supra* note 141, at 20.

157 *Id.*

158 *Id.*

159 *Id.*

portfolio and creates an action plan to implement the desired portfolio.[160]

Two important points bear noting with respect to IRP considerations. First, IRPs generally aim to take a holistic look at how demand can be met. The original idea of the IRP was to encourage utilities not just to evaluate new generation options but also to consider demand-side measures such as energy efficiency or conservation to reduce or alter overall demand.[161] Thus, state rules typically mandate that "utilities consider all feasible supply-side, demand-side, and transmission resources that are expected to be available within the specified planning period, and some states get more specific than that."[162] Still, only some states expressly require that plant life and expected decommissioning dates be taken into account.[163]

Second, IRPs specifically seek to assess different kinds of risk.[164] As the Energy Policy Act of 1992 states, the IRP process "shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk . . . ."[165] Again, which risks are assessed in any given IRP varies across states, but it is important to note that risk assessment is a core part of the IRP process. Thus, one IRP "best practices" manual suggests that possible resource plans should be evaluated for their "adaptability and resilience of plan in face of risks."[166] And a recent survey observed that common risks assessed in IRP sensitivity cases and scenario analyses include "fuel prices (coal, oil, and natural gas), load growth, electricity spot prices, variability of hydro resources, market structure, environmental regulations, and carbon dioxide and other emission regulations."[167]

Looking at western IRPs specifically, there is a large degree of commonality. While California now utilizes a long-term procurement planning process rather than an IRP process per se, all other states west

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160 *Id.* For a historical overview of IRP, see, for instance, Joseph H. Eto, *An Overview of Analysis Tools for Integrated Resource Planning*, 15 ENERGY 969 (1990).

161 McAllister, *supra* note 146, at 2151; THE TELLUS INST., BEST PRACTICES GUIDE: INTEGRATED RESOURCE PLANNING FOR ELECTRICITY 3, http://pdf.usaid.gov/pdf_docs/PNACQ960.pdf.

162 WILSON & PETERSON, *supra* note 142, at 8–10.

163 *Id*. at 11–13.

164 For a historical criticism of IRPs' treatment of risk, see, for instance, Shimon Awerbuch, *The Surprising Role of Risk in Integrated Resource Planning*, 6 ELECTRICITY J. 20 (Apr. 1993).

165 Energy Policy Act of 1992, 42 U.S.C. §§ 13201−13574 (2012).

166 THE TELLUS INST., *supra* note 161, at 37.

167 WILSON & PETERSON, *supra* note 142, at 3−4.

of the Continental Divide mandate IRPs, save Alaska.[168] Some states only require investor owned utilities to submit IRPs, so not all utilities within a state are covered,[169] while other states require all utilities regulated by the public utility commission to file an IRP.[170]

In terms of resources, western states generally require utilities to address both supply-side and demand-side resources in their IRPs. This includes current electric loads, consumer data, customer trends, and energy efficiency considerations,[171] as well as information about the utility's current generation fleet, the costs associated with generation unit maintenance, and the current fleet's capacity. Arizona, Colorado, Nevada, New Mexico, and Utah require utilities to discuss the feasibility of including or expanding their use of renewable resources,[172] including, in all those states but Utah, the utility's compliance with the state's renewable portfolio standard.[173] Moreover, even when not mandated by state law, utilities are increasingly planning for the inclusion of renewable resources in their IRPs,[174]

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168 *Id*. at 5. Most western states mandate IRP filing through statutes, regulations, or a combination of the two. Idaho, Oregon, and Utah established their requirements via administrative adjudicative decisions. *See* Idaho Electric Utility Conservation Standards and Practices, 100 P.U.R. 4th 159 (1989); Public Utility Commission of Oregon, 255 P.U.R. 4th 367 (2007); PacifiCorp, 135 P.U.R. 4th 306 (1992).

169 *See, e.g.*, COLO. CODE REGS. § 723-3:3600 (2015) ("[c]ooperative electric associations engaged in the distribution of electricity . . . are exempt from these rules.").

170 MONT. ADMIN. R. 38.5.2001 (2015) ("[e]lectric utilities under the jurisdiction of the Montana public service commission are required to file least cost plans as outlined below.").

171 *See, e.g.*, N.M. CODE R. § 17.7.3.7(C) ("demand-side resources means energy efficiency and load management"); *id.* at § 17.7.3.9(C)(9) ("The utility's description of its existing resources used to serve its jurisdictional retail load at the time the IRP is filed shall include . . . description of existing demand-side resources, including (1) demand-side resources deployed at the time the IRP is filed; and (2) demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed; information provided concerning existing demand-side resources shall include, at a minimum, the expected remaining useful life of each demand-side resource and the energy savings and reductions in peak demand, as appropriate, made by the demand-side resource.").

172 ARIZ. ADMIN. CODE § 14-2-703(D)(9) (2015); COLO. CODE REGS. § 723-3:3604(k) (2015); NEV. ADMIN. CODE § 704.9489(5) (2015); N.M. CODE R. § 17.7.3(H)(6) (2015); PacifiCorp, 135 P.U.R. 4th 306 (1992); *see, e.g.*, COLO. CODE REGS. § 723-3:3604(k) (2015) (requiring utilities to consider at least three alternative resource plans, one of which includes "proportionately more renewable energy resources").

173 ARIZ. ADMIN. CODE § 14-2-703(E)(2) (2015); COLO. CODE REGS. § 723-3:3604(k) (2015); NEV. ADMIN. CODE § 704.937(1) (2015); N.M. CODE R. § 17.7.3(G)(2) (2015). Utah's renewable portfolio standard is often considered a voluntary goal rather than a mandate because it includes an exception for when compliance is not cost-effective. *See* UTAH CODE ANN. §§ 54-17-602(1)(a), 54-7-12(2)(c)(ii).

174 Bolinger & Wiser, *supra* note 141, at 1.

perhaps because renewables can help mitigate cost risks (both fuel and carbon costs) associated with fossil-based portfolios.[175]

As to risk, western states generally require some degree of risk analysis in their IRPs, although the details of this mandate again vary by state. Common risks covered by state requirements include compliance with environmental regulations, fuel cost and availability, reliability and operational risks, the occurrence of forced outages, and load growth risk (*i.e.*, projections of the degree to which electricity demand may increase). Arizona, Colorado, Montana, Nevada, and Oregon suggest that utilities should include other risks as they see fit.[176] Arizona, Colorado, Montana, Nevada, Oregon, and Utah require utilities to assess the environmental impact of their proposed resource portfolios by providing data about emissions and regulatory compliance.[177] Arizona, Colorado, and New Mexico require utilities to include information about water consumption quantities, rates, and intensity.[178] Montana includes water availability in their risk assessment requirements, although the language is not mandatory.[179] Oregon identifies hydroelectric generation as a source of risk and uncertainty that utilities must discuss.[180]

B. Western IRPs, Water, and Drought

To evaluate how western utilities address water consumption, and in particular the risk of drought, we conducted an original analysis of IRPs in ten states: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.[181] Altogether, we

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175 *Id.*

176 ARIZ. ADMIN. CODE § 14-2-703(E)(h); COLO. CODE REGS. § 723-3:3609(b); MONT. ADMIN. R. 38.5.8219(5) (2015); NEV. ADMIN. CODE § 704.948(1) (2015); Public Utility Commission of Oregon, 255 P.U.R. 4th 367 (2007).

177 ARIZ. ADMIN. CODE § 14-2-703(B)(1)(p) (2015); COLO. CODE REGS. § 723-3:3604(g) (2015); MONT. ADMIN. R. 38.5.2004 (2015); NEV. ADMIN. CODE § 704.937(3), (4) (2015); PacifiCorp, 135 P.U.R. 4th 306 (1992).

178 ARIZ. ADMIN. CODE § 14-2-703(B)(1)(q); *see also* COLO. CODE REGS. § 723-3:3604(h) (2015); N.M. CODE R. §17.7.3.9(C)(12) (2015).

179 MONT. ADMIN. R. 38.5.8219(5) (2015); Public Utility Commission of Oregon, 255 P.U.R. 4th 367 (2007).

180 Public Utility Commission of Oregon, 255 P.U.R. 4th 367 (2007).

181 Because California now uses a long-term resource procurement process rather than an IRP process, we did not include California utility planning documents in our analysis.

analyzed thirty-three utility IRPs,[182] including the IRPs for the largest utility in each of the analyzed states.[183]

We proceeded by acquiring and analyzing the most recent IRP filing from utilities in each western state with an IRP requirement. Prior to reviewing the IRPs, we developed a standardized list of risk factors that an IRP might assess. We then evaluated each IRP to determine whether the IRP addressed any and each of the factors on the list of possible risks. These included whether the IRP evaluated: load growth, environmental regulation compliance, generation fuel shortages or market volatility, environmental impact and degradation risks, the risk of implementing new renewables, operation costs, and climate change risk.

Because our aim was to determine what attention, if any, IRPs give to water availability and drought planning, we also included several risk factors related to water as points of focus. Specifically, we determined whether the IRP addressed a utility's water consumption needs, water costs, the cooling efficiency of its plants, water shortages in relation to hydroelectricity production, future drought risk, and whether the IRP included a plan or solution to deal with drought.

The results of our analysis were illuminating. Specifically, four trends emerge in western IRPs with respect to water planning:

First, utilities clearly focus on risk. Of the IRPs reviewed, every utility addressed some kind of risk. This finding should be expected, since planning is not meaningful if risk is not taken into account. But the contrast of this finding with how little attention utilities overall give to water risk is stark.

Second, less than half—only thirty-nine percent—of the reviewed IRPs evaluated water consumption needs. Thus, even though utilities

182 Specifically, we analyzed the IRPs from Arizona Public Service; Tucson Electric Power; UniSource; Colorado Springs Utilities; Tristate Electric; Xcel Energy: Public Service Company of Colorado; Idaho Power; Montana-Dakota Utilities; Northwest Energy; Nevada Energy; El Paso Electric; Public Service of New Mexico; Xcel Energy New Mexico; Clark Public Utilities; Eugene Water and Electric; PacifiCorp; Avista Utilities; Benton Public Utilities District; Chelan County Public Utilities District; Clark Public Utilities; Cowlitz Public Utilities District; Franklin County Public Utilities District; Grays Harbor Public Utilities District; Inland Power and Light; Lewis County Public Utilities District; Orcas Power and Light; Puget Sound Energy; Seattle City and Light; Snohomish County Public Utilities District; Tacoma Power; Black Hills Power; Cheyenne Light, Fuel, and Power; and Wyoming Municipal Power Agency.

183 Notably, the PacifiCorp IRP covers multiple states. That utility prepares a single IRP for its entire system and then files the same document in all those states where it serves customers.

are very focused on risk in their IRPs, those analyses are comparatively less centered on water, even though water is intrinsically connected to electricity production.

Third, even fewer of the reviewed IRPs—twenty percent and twelve percent, respectively—expressly address past water shortages relevant to hydroelectric power or the risk of future drought or water shortages. This finding is particularly telling given how important of a role drought is likely to play for electricity production in the West in a future altered by climate change.

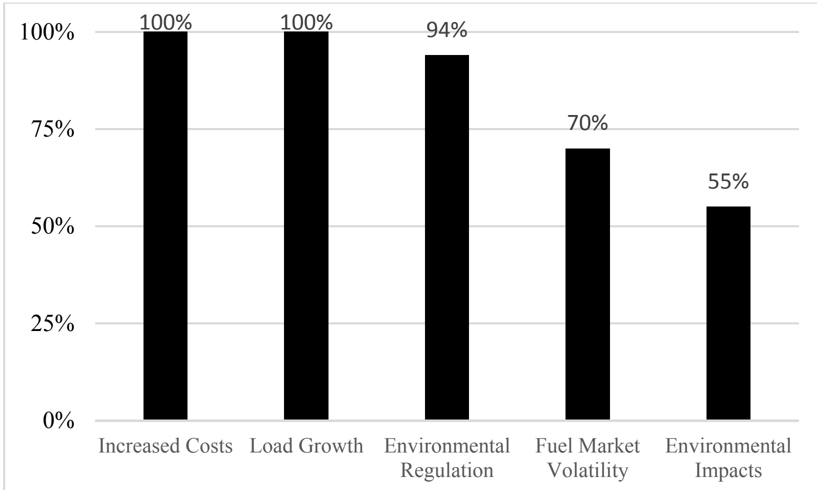
Finally, simply because a utility discusses present water needs or future drought risk does not mean they will necessarily take the next step of actually finding a way forward to deal with water consumption or drought in their IRP. Some IRPs that addressed water needs did not address the risk of drought, and most that acknowledged drought risks did not actually develop a plan in the IRP to address that concern. In short, then, when it comes to dealing with water and drought, much is left to be desired in how many western utilities currently execute their IRPs.

After detailing each of these findings below, we return to the theme of how utilities might better integrate electricity and water planning in Part IV.

1. Overall Risk Assessment

A clear focus of western IRPs is risk. Of the thirty-three IRPs reviewed, every single one addressed some kind of risk. Most popular was the risk of increased electricity costs, which every reviewed IRP evaluated. It makes sense that IRPs examine this, because a core purpose of electricity regulation is to keep prices low. However, other risk factors were close behind. Specifically, all of the reviewed IRPs assessed load growth, or the likelihood of increased demand for electricity, which most state statutes and IRPs categorize as a kind of risk. It also makes sense that IRPs would assess this, because their very purpose is to analyze different alternatives for meeting electricity demand into the future. All but two of the reviewed IRPs raised environmental regulation as a risk. Seventy percent of the reviewed IRPs discussed fuel market volatility as a risk, and fifty-five percent evaluated environmental impacts as a risk.

Figure 1. Non-water risk factors addressed in western IRPs



The IRPs' focus on risk in this way is noteworthy for at least two reasons. First, the fact that these documents address so many different kinds of risk demonstrates that this is a key area of inquiry for the IRP process. Risk assessment is integral to electricity resource planning. Again, this point is potentially self-evident, but of course IRPs could have evolved in a different way, and their focus on risk is an important observation in contrast to the next point.

Second, the kind of risks that IRPs focus on is telling. Each of the risks identified above is tied directly to utility profitability, save perhaps environmental impacts, although there too a connection can be easily made.[184] In contrast, when the risk factors become less directly tied to traditional inputs to utility revenues (*e.g.*, load forecasts and fuel costs vs. water availability and drought risks), the rate at which IRPs assess these risks quickly declines. The fact *that* IRPs focus on risk, then, stands in stark contrast to *how* utilities assess risk in their IRPs. These documents appear to center, perhaps predictably, on immediate profitability of the corporate entity. Non-financial factors that also might affect the long-term sustainability of the electricity system are, overall, less central to the IRP process, even though such factors are vital to utility operation and function. This becomes particularly clear in how western utility IRPs evaluate risks related to water.

184 Liability for environmental impacts, like any legal liability, can cut into profits.

2. Water Needs

Despite the West's aridity and the reliance of western utilities on both hydropower and freshwater for cooling thermoelectric plants, less than half of the IRPs we reviewed addressed water use needs as part of their analyses. Specifically, only thirteen of the thirty-three IRPs, or thirty-nine percent, addressed this topic. This is telling indeed, particularly when contrasted with the fact that every single IRP evaluated load growth and generation cost risks, and that more than three-quarters of IRPs evaluated environmental regulatory cost risks—and just less than three-quarters assessed fuel market volatility questions. Water, in short, pales in comparison to other more financial-focused risks that western utilities evaluated in their IRPs.

Moreover, what utilities evaluated in their IRPs with respect to water was not uniform within states. Of the thirteen IRPs that addressed water needs, nine also provided specific water consumption data, but four did not. Likewise, while all six of the Arizona and New Mexico IRPs we reviewed dealt with overall water needs for their generation fleets, only one of the two Oregon IRPs did, and only two Washington IRPs did. This suggests divergence in utility practices for completing IRP analyses, and in particular, lack of uniformity among utilities in determining whether water supply is something that should be planned for when evaluating strategies to address future electricity demand. In fact, and somewhat remarkably, only four utilities assessed the risk of increased water costs in their IRPs. Two were utilities that also evaluated water needs, but the other two were not. Again, this demonstrates a strong difference between utilities' virtual unanimity in evaluating direct costs and financial risks in their IRPs and a much more scattershot approach in terms of assessing water risks. It also underscores the divergence among utilities in whether and how water risks are assessed in the IRP process.

Arizona Public Service (APS) provides a leading example of how utilities might assess water use in their IRPs. The APS IRP contains a detailed water consumption analysis for all existing generating units as well as for each portfolio under review.[185] APS identifies cooling as their biggest draw of water but also explains that their facilities use water for power augmentation, emissions control, auxiliary cooling, supporting chemical treatment processes, and for additional domestic purposes.[186] In addition to providing information about its water use,

185 ARIZ. PUB. SERV., 2014 INTEGRATED RESOURCE PLAN 67 (2014).
186 *Id.* at 118.

APS's IRP also outlines a three-step approach for reducing water intensity: employing new cooling technologies for new generating resources, improving water efficiency at existing facilities, and increasing reliance on energy efficiency and renewable energy resources.[187] For example, in the various portfolio analyses in its IRPs, APS assumes the use of dry or hybrid-cooled technology for newly implemented natural gas facilities.[188] However, although APS provides an in-depth assessment of its water use and the need to reduce water intensity, its IRP does not acknowledge the risk of future drought.

3. Water Shortages for Hydroelectricity

Utilities addressed water shortages and seasonal flows relevant to hydroelectricity in their IRPs even less often than they did their overall water needs. Of the thirty-three IRPs reviewed, only seven—a mere twenty-one percent—evaluated water shortages and their potential impact on the utility's hydroelectric generation resources.

On one hand, this is remarkable, particularly given the longstanding aridity of the West, the frequency with which droughts arise, and the significant use of hydroelectricity in the region. On the other hand, the lack of discussion of water shortages in these IRPs may reflect the reality that utilities know they must acquire water elsewhere whenever necessary, albeit at an increased cost to ratepayers.

Still, an interesting trend manifests among the utilities that did discuss water shortages and seasonal flows with respect to hydroelectricity: of the seven IRPs that did discuss this, only four were from utilities that also addressed water use needs for their electricity supply. So, interestingly, there does not appear to be a direct correlation between whether a utility evaluates water needs and whether it addresses the potential for water shortages for hydroelectricity.

187 *Id.* at 118–20.
188 *Id.* at 38.

Table 5. Assessment of potential water shortages by utilities with hydroelectricity in generation portfolios

Amount of hydroelectricity in utility's portfolio	Number of utilities whose IPRs discussed potential water shortages	Number of utilities whose IPRs did not discuss potential water shortages
> 0% ≤ 25%	1	5
> 25% ≤ 50%	2	0
> 50% ≤ 75%	1	0
> 75%	0	0
Utility uses hydroelectricity but IRP does not provide portfolio %	2	17

Thus, as Table 5 illustrates, seventy-nine percent of utilities that reported use of hydroelectricity in their IRPs did not discuss potential water shortages, and only twenty-one percent of utilities that did report employing hydroelectricity in their fleet discussed the potential of future water shortages. In other words, the fact that our overall analysis shows that western utility IRPs do not uniformly address water shortages for hydroelectricity production cannot be explained away by dividing the IRPs into groups for utilities that utilize hydroelectricity and those that do not. Many utilities that rely on hydroelectricity assessed water shortages in their IRPs, but a large majority did not.

Seattle City and Light's IRP provides an example of how utilities might address water shortage risks related to hydroelectricity production. Its IRP contemplates the effects that climate change will have on their hydroelectric fleet.[189] The IRP acknowledges that warmer temperatures will affect seasonal electricity and demand for heating and cooling, and that winter snow pack will melt earlier, affecting seasonal generating capability, while melting glaciers will cause changes in river flows.[190] Seattle City and Light also addresses the variability in flow caused by water shortages. Accordingly, its IRP evaluates winter-resource additions and conservation efforts in each portfolio.[191]

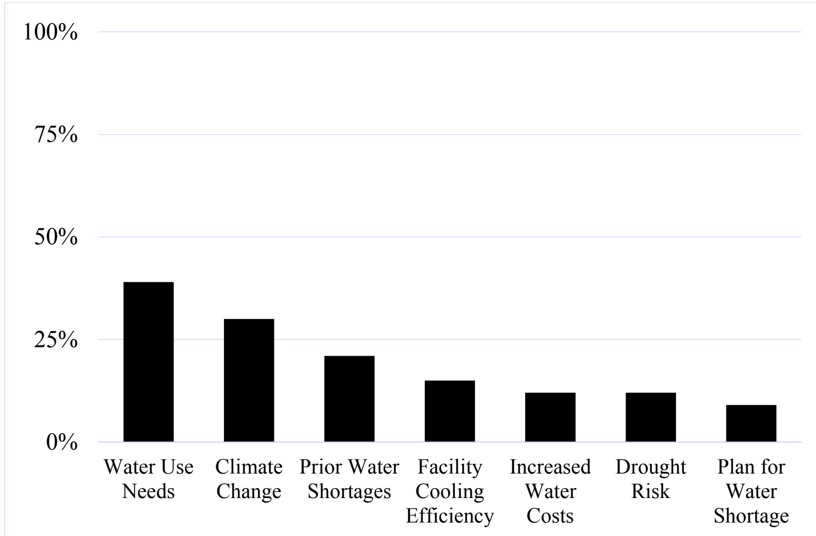
189 SEATTLE CITY LIGHT, 2012 INTEGRATED RESOURCE PLAN (2012).
190 *Id.* at 25.
191 *Id.*

4. Drought and Drought Planning

Just as only a minority of utilities assess past water shortages in their IRPs, only a few of the reviewed documents evaluated future drought risk. Specifically, only four—or twelve percent—of the thirty-three reviewed IRPs addressed drought: those of Eugene Water and Electric, Public Service Company of New Mexico, Seattle City and Light, and Tucson Electric Power. Notably, each of these utilities also evaluated water supply needs in its IRP, but that means that only a quarter—three of twelve—of the utilities that assessed water needs for their generation portfolio also addressed drought risk, even though they explicitly acknowledged in their IRPs that water use is an issue for their generation fleets. Moreover, even though four utilities identified drought as a risk to their electricity supply, only two of these four utilities actually developed a plan in their IRP to address the concern. Again, then, this draws a clear contrast to how utilities address other risks in their IRPs, particularly when comparing financial risks (ubiquitously) and water-focused risks (much more sporadically, unevenly, and in many cases not at all).

Figure 2 drives this point home. It shows that of the wide variety of water-related risks a utility might assess in its IRP, no factor saw even forty percent of IRPs addressing it. Moreover, all but two factors fell below the twenty-five percent mark, including, quite notably, the risk of increased water costs to the utility. Also quite telling is how the IRPs addressed climate change, which is directly related to water needs for electricity production. Only thirty percent of the thirty-three IRPs evaluated climate change as a risk. Perhaps even more importantly, though, only half of the ten utilities that evaluated climate change risks in their IRPs also assessed water needs—and only two of the ten also analyzed drought risks for their generation portfolio. Given how directly linked climate change is to water consumption, water availability, and drought, the dearth of analyses by utilities on this score is noteworthy. It means that even when a utility's IRP expressly acknowledges climate change as a risk, only sometimes will it evaluate water needs—and the vast majority of time it still will not deal with drought.

Figure 2. Water risk factors addressed in western IRPs



Public Service Company of New Mexico (PNM) provides the best example of an IRP that creates a plan for actually dealing with drought.[192] PNM's IRP begins by noting that "providing for a reliable, sustainable water supply is essential to the successful operation of PNM's generation fleet and is the focus of the Water Resources Group."[193] The IRP acknowledges that drought affected the region in the past, and that a recurrence of a similarly severe drought "could affect the availability of the SJGS and Four Corners plants because they use surface water for cooling."[194] PNM then outlines options for mitigating the effect of a water shortage on its fleet, including steps for maximizing water conservation, increasing water rights acquisitions, entering into shortage sharing agreements, and implementing water-efficient technologies into the generation fleet.[195] Discussing these options, it details its plan to rely on water sharing agreements with tribes and other water users in drought-affected areas. Specifically, PNM signed a 40-year agreement with five cities to provide cooling water for one of their existing facilities.[196]

192 PUB. SERV. CO. OF N.M., INTEGRATED RESOURCE PLAN 64 (2014).
193 *Id.* at 24.
194 *Id.*
195 *Id.*
196 *Id.*

5. The Importance of State Law Requirements

State IRP requirements establish the basic parameters for utility IRPs, and it is clear from our analysis that state law requirements likewise influence the depth of IRP discussions on water in the West.

Only three states—Arizona, Colorado, and New Mexico—require discussion of water consumption rates in utility IRPs.[197] Importantly, all but one of the IRPs we evaluated in these states discussed water consumption needs.[198] Interestingly, despite the fact that Colorado's law requires discussion of annual water consumption, water intensity of the utility's generating system, and projected water consumption,[199] one of the three utility IRPs we evaluated from that state failed to provide water consumption data. Nonetheless, despite this exception, it is clear that state requirements mandating assessment of water needs influence the scope and content of IRPs.

In fact, only one utility included water consumption data in their IRP when doing so was not required by state law. PacifiCorp presented data on water consumption for its power plants, although none of the jurisdictions where it files its system-wide IRP—Idaho, Oregon, Utah, Washington, and Wyoming—require inclusion of water consumption data.[200] This stands in stark contrast to other utilities that did address water consumption, all of which were filed in states that mandate this consideration. Likewise, while Montana suggests water availability as a potential source of risk (but does not mandate its inclusion in utility IRPs), the IRPs we analyzed for that state uniformly did not address water consumption.[201] Thus, if states would like the utilities that provide electricity within their jurisdictions to address the connection

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197 ARIZ. ADMIN. CODE § 14-2-703(B)(1)(q); *see also* COLO. CODE REGS. § 723-3:3604(h) (2015); N.M. CODE R. § 17.7.3.9(C)(12) (2015).

198 These IRPs included those for Arizona Public Service, Tucson Electric Power, UniSource Energy Services, Tristate Electric, Xcel Energy Colorado, El Paso Electric, Public Service Company of New Mexico, and Xcel Energy New Mexico. *See* ARIZONA PUBLIC SERVICE, 2014 INTEGRATED RESOURCE PLAN 108–09 (2014); TUCSON ELECTRIC POWER, 2014 INTEGRATED RESOURCE PLAN 166 (2014); UNISOURCE ENERGY 2014 INTEGRATED RESOURCE PLAN 51–52 (2014); PUBLIC SERVICE COMPANY OF COLORADO, 2011 ELECTRIC RESOURCE PLAN 78 (2011); TRISTATE GENERATION AND TRANSMISSION ASSOC., INTEGRATED RESOURCE PLAN/ELECTRIC RESOURCE PLAN 150 (2010); EL PASO ELECTRIC CO., INTEGRATED RESOURCE PLAN OF EL PASO ELECTRIC COMPANY FOR THE PERIOD 2015–2034 ATTACHMENT A (2015)

199 COLO. CODE REGS. § 723-3:3604(h) (2015).

200 PACIFICORP, 2015 INTEGRATED RESOURCE PLAN VOLUME II-APPENDICES 94–95 (2015).

201 MONT. ADMIN. R. 38.5.8219(5) (2015).

between electricity and water, an obvious first step may be to mandate such discussions in their IRPs.

This trend is made even clearer when other water-related factors are taken into account. Indeed, only eight of the thirty-three utility IRPs—or twenty-four percent—contained any type of water discussions not required by state law. Four of the eight presented information about water consumption needs, and each IRP touched on some aspect of water planning (either cost, cooling efficiency, or the potential for shortages).[202]

Table 6. IRPs addressing water factors by state[203]

State	State IRP water mandate?	Water use needs	Prior water shortages	Facility cooling efficiency	Increased water costs	Drought risk
AZ	Yes	3/3	0/3	2/3	0/3	1/3
CO	Yes	3/3	1/3	0/3	1/3	0/3
ID	No	1/2	1/2	1/2	0/2	0/2
MT	No	0/2	0/2	0/2	0/2	0/2
NV	No	0/1	0/1	0/1	1/1	0/1
NM	Yes	3/3	2/3	1/3	1/3	1/3
OR	No	2/3	1/3	1/3	0/3	0/3
UT	No	1/1	0/1	1/1	0/1	0/1
WA	No	3/15	2/15	2/15	1/15	1/15
WY	No	1/4	0/4	1/4	0/4	0/4

Table 6 further details the differences among states that impose water assessment requirements for IRPs and those that do not. As the table makes clear, where a state mandates evaluation of water in its utilities' IRPs, those utilities not only uniformly assess water needs, but the likelihood that their IRPs will also evaluate other water-related risks goes up. Indeed, for each of the three states that have IRP water consideration mandates, at least one utility evaluated almost every water-related risk factor. By contrast, the proportion of utilities in non-water-mandated IRP states that assessed water needs is much lower—and the likelihood that such IRPs will have assessed other water-related risks is lower still.

202 *See supra* Part III.B.4.

203 The total number of IRPs listed in Table 6 exceeds thirty-three, because for purposes of this table only, we counted PacifiCorp's single IRP in the tally for each of the states where it was filed (Idaho, Oregon, Utah, Washington, and Wyoming).

Again, then, the lack of water planning among utilities that are not required by state law to include such assessments in their IRPs underscores the strong influence that state requirements have on what is evaluated in an IRP. In short, if state law does not prompt a utility to consider water in their planning process, the IRPs we examined illustrate that they are unlikely to do so on their own accord. Likewise, although no state requirements currently mandate consideration of drought risk in utility IRPs, two of the four utilities that did discuss drought in their IRPs were in jurisdictions that require information about water consumption and intensity.[204] This may indicate that requiring some analysis about water in an IRP could also encourage utilities to address drought risk in their planning process.

IV
POSSIBLE REGULATORY RESPONSES

The overall lack of planning for water consumption, and in particular for the risk of drought, in western utility IRPs highlights several paths for improving electricity development in this region. These paths might be categorized along a spectrum. That spectrum runs from deeply integrated electricity and water planning on one end to entirely separate planning processes on the other. Thus, different options for reforming how utilities plan for water reflect the degree to which an IRP would further integrate water and electricity planning.

While certainly not an exhaustive list, options for more closely integrating water and electricity planning include: (1) mandating consideration of water factors in IRPs, including compelling disclosure of drought risks; (2) mandating a showing that sufficient water exists for generation resources before development can proceed; (3) requiring drought and water shortage plans within IRPs; and (4) holistically integrating water and electricity planning, perhaps by linking IRPs and state water planning processes.

Presumptively, the benefits of combining electricity and water planning under any of these options should be significant. Were utilities already extensively evaluating water concerns in their IRPs, an argument could be made that mandating integration would be

204 Arizona Public Service and Public Service of New Mexico both addressed the risk of drought in their IRP, and both Arizona and New Mexico require utilities to include information about water consumption in their IRPs. Eugene Water and Electric in Oregon and Seattle City Light in Washington also addressed the risk of drought, although neither state requires information about water associated risks in utility IRPs.

redundant, and thus, inefficient. However, given the low levels of planning for water by utilities—as well as their extensive use of this resource—it appears that there may be something to gain from further integrating how water and electricity are planned for and evaluated. Indeed, it is well-documented in other contexts that combining regulation to look more holistically beyond a narrow sphere can improve operation of the law by, for instance, making the regulatory regime more effective, creating planning synergies between agencies, improving the planning of specific projects, and ferreting out defects in proposals that otherwise might not have been a focus of the evaluative or permitting process.[205]

Indeed, it makes particular sense that electricity and water planning should be combined more tightly. Water is not an external, irrelevant resource to electricity production. It is a fundamental input to that system—the actual "fuel" for hydroelectricity production, and a necessary medium for thermoelectric generation. Moreover, water is neither fungible nor simply a commodity. It cannot be replaced or substituted as can, say, coal, gas, or petroleum. And it has immense public value in a wide-ranging variety of uses, including for agriculture, recreation, and residential consumption. For all these reasons, evaluating water consumption by the electricity system—and the risk that the lack of water poses to that system—could be quite beneficial to the public. Water and electricity, after all, both straddle the line of being public goods needed by all as well as private commodities with independent commercial value.

Accordingly, this Part outlines each of the four options identified above for improving IRPs by further integrating water and electricity planning, including sketching the likely limits and possible benefits of each option. On the spectrum of integration, we begin by addressing the most minimal of the four options and move progressively to the one that would most deeply integrate water and electricity planning.

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205 *See, e.g.*, ENV'T LAW INST., WET GROWTH: SHOULD WATER LAW CONTROL LAND USE? (Craig Anthony Arnold ed., 2005); Robert Haskell Abrams, *Water, Climate Change, and the Law: Integrated Eastern States Water Management Founded on a New Cooperative Federalism*, 42 ENVTL. L. REP. NEWS & ANALYSIS 10433 (2012); Sarah Bates, *Bridging the Governance Gap: Emerging Strategies to Integrate Water and Land Use Planning*, 52 NAT. RESOURCES J. 61 (2012); Lincoln L. Davies, *Just a Big, "Hot Fuss"? Assessing the Value of Connecting Suburban Sprawl, Land Use and Water Rights Through Assured Supply Laws*, 34 ECOLOGY L.Q. 1217, 1271–74 (2007); Lincoln Davies, *Power Forward: The Argument for a National RPS*, 42 CONN. L. REV. 1339 (2010).

A. Water Consumption Consideration / Drought Risk Disclosure

A basic starting place for integrating water concerns into IRPs would be to mandate evaluation of water consumption in the IRP process. This is, in fact, what some jurisdictions, including Arizona, Colorado, and New Mexico, have already done. As the Colorado rule states, utilities must include in their IRPs

> [t]he annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWh) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.[206]

This is precisely the kind of information that can help improve IRPs by forcing the utility to consider the water impacts of its plans and giving the public a window into what those impacts may be. Such requirements also seem to work. As noted above, of the nearly three dozen IRPs we evaluated, virtually all of those that actually evaluated water use were in states with a requirement such as this.[207] Water-based analyses were noticeably absent, almost unanimously, from IRPs in states that did not have this type of requirement—in one case, even where the state statute suggested that water availability is a risk factor that IRPs may want to assess.[208]

Similar to mandating that IRPs assess water needs, states might also impose a requirement that utilities disclose in their IRPs any risk of drought to their generation fleet. This would function much the same way a water consumption consideration mandate would, only in mirror-image. Utilities would be compelled to disclose in their IRPs whether a risk of drought might impact the generation portfolios under consideration during a given period in the future, say ten or twenty years, or whichever planning horizon their state uses for the IRP. At a minimum, this would make utilities' decisional processes more transparent. Potentially, it could encourage them to begin considering how to address potential drought risks as well.

Approaches such as these might promise a variety of benefits. Because these requirements would not force utilities to act in any given way, they would maintain flexibility for the utility. At the same time,

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206 COLO. CODE REGS. § 723-3:3604(h).

207 *See supra* Part III.B.2-4.

208 *See id*.

they would provide additional information both for the utility itself to consider and for the public to weigh. That is, to the extent utilities have not been considering water consumption already in their planning processes, this requirement would compel them to at least take the question into account in their decision-making—akin, perhaps, to what NEPA requires in other contexts.[209] As some research has shown, the mere procedural evaluation of a factor, such as in the NEPA context, may also improve the substantive results.[210] Likewise, by increasing the transparency of utility decision-making in this context, requirements that utilities evaluate water or drought impacts might also yield the ancillary benefit of heightening public involvement in the planning process.

Of course, as the most minimal of possible options for integrating water and electricity planning, requirements such as these are likely to also be the most limited in terms of the benefits they do offer. The flip side of their flexibility is that they will not necessarily foreclose electricity development that could be water- or drought-risky. That is, if utilities follow these requirements only to technically satisfy the rule—to give them lip service—they may be worth very little. Further, if the public sees the requirements as sham mandates as a result, they may actually disillusion the populace with the IRP process, rather than encouraging citizens to become more involved in it.

B. "Assured Supply" Requirements

A more vigorous option than simply requiring utilities to consider water use or disclose drought risk in their IRPs would be to foreclose generation portfolios where the utility cannot demonstrate reliable sources of water sufficiently into the future.[211] Some jurisdictions already enforce such mandates in analog situations. For instance,

209 42 U.S.C. §§ 4321−4347.

210 *See, e.g.*, Robert W. Adler, *In Defense of NEPA: The Case of the Legacy Parkway*, 26 J. LAND RESOURCES & ENVTL. L. 297 (2006); Michael C. Blumm & Keith Mosman, *The Overlooked Role of the National Environmental Policy Act in Protecting the Western Environment: NEPA in the Ninth Circuit*, 2 WASH. J. ENVTL. L. & POL'Y 193 (2012); John Ruple & Mark Capone, *NEPA—Substantive Effectiveness Under a Procedural Mandate: Assessment of Oil and Gas EISs in the Mountain West*, GEO. WASH. J. ENERGY & ENVTL. L., http://ssrn.com/abstract=2585207 (forthcoming 2016).

211 Of course, such a requirement need not be included in the IRP process itself, and it may make more sense procedurally elsewhere. It could, for instance, be imposed as part of a generation acquisition, siting, or permitting process. Nonetheless, it would seem logical to at least connect such a requirement to the IRP process, even if the mandate is enforced through a different mechanism.

California and Oregon, among other jurisdictions, compel real estate developers to prove that they have adequate water supplies secured before they can build new homes.[212] These "assured supply" laws appear to create some benefits, including sometimes preventing developments where water would not have been available.[213] Notably, a few states also now impose varieties of requirements akin to assured supply mandates in the electricity generation context itself.[214]

The possible benefits of including a similar mandate for IRPs should be fairly obvious. If the requirement helps avoid generation portfolios that are unnecessarily water-heavy, these laws could help conserve water for other uses. Likewise, if they prevent generation portfolios that would be risky from a drought perspective, they also could make the electricity system more reliable. In this sense, then, such mandates could force utilities to internalize the social cost of unreliability (or increased water costs) that might otherwise be externalized onto ratepayers.

Still, this type of requirement might not offer only benefits. To the extent that utilities already consider water and drought where appropriate, changing IRPs in this way could simply add an additional and unneeded regulatory layer, thus creating inefficiency and redundancy. Likewise, if the requirement were set too stringently, it could unnecessarily increase electricity prices by overcompensating for drought risk. On the flip side, if the requirement is set too loosely, it could provide a false sense of security, which could be particularly

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212 *See* CAL. GOV'T CODE § 66473.7 (2005); OR. REV. STAT. §§ 197.015, 197.175(2) (2015); OR. ADMIN. R. 660-015-0000(5), 660-015-0000(6), 660-015-0000 (2016).

213 Lincoln L. Davies, *Just a Big, "Hot Fuss"? Assessing the Value of Connecting Suburban Sprawl, Land Use and Water Rights Through Assured Supply Laws*, 34 ECOLOGY L.Q. 1217, 1265–69 (2007).

214 Typically, this is part of generation facility siting or permitting processes. *Cf. supra* note 211. Arizona and Oregon, for instance, require a showing of water rights or source, *see* ARIZ. ADMIN. CODE R14-3-219(4)(a)(v); OR. ADMIN. R. 345-001-0010(1)(e), (l), (o), and Oregon goes further, mandating assessment of water consumption for generation facilities. *See* OR. ADMIN. R. 345-001-0010(1)(o). Washington takes yet another step and requires not only evaluation of water consumption and availability but also alternatives to water use for facility cooling. *See* WASH. ADMIN. CODE 463-60-165.

Notably, however, in the West, a showing of water rights is not necessarily a demonstration of a real water supply. Nonetheless, once a state decides to mandate a showing of water rights, it should be simple enough to also require a demonstration of an actual water supply. Moreover, the fact that some jurisdictions already have experience with versions of these requirements should be helpful to those that want to adopt a kind of assured supply mandate for electricity production facilities.

problematic if the requirement failed to foreclose the true risk of drought. To be sure, climate science is getting more and more accurate, but it is far from perfect, and if the past has shown anything with respect to energy forecasting, it is that energy futures are notoriously difficult to predict.[215]

C. Mandatory Drought Planning

A third option might be to require utilities not just to disclose drought risk but to mandate that they affirmatively plan for it once it is identified. This is, for instance, what Public Service Company of New Mexico has done. Their IRP does not stop at simply noting that drought could present problems for their generation portfolio. They actively identified solutions to this problem and then chose among those options to guard against it.[216]

The salutary effect of such an IRP requirement would seem direct. It could have all of the improved planning benefits of the first two options, including possibly creating better coordination among regulatory bodies, reducing water consumption by the electricity sector, and making generation portfolios more reliable. It also would help utilities identify ways to bracket drought risk in advance, and thus presumably prepare them to deal with any such problems that arise, rather than leaving them in a situation where they have to quickly adapt once water supplies become tighter or dry up.

Nonetheless, this kind of mandate would not necessarily solve all problems. Planning does not always translate into prevention, so if a utility did not take appropriate steps to prepare for the drought—that is, to implement its plan—the plan itself might be worth quite little. Or, if the utility plans for a scenario that does not turn out to be true, or is worse than expected, such a mandate may be only a partial solution. Examples in history where planning requirements did little to prevent disaster are plentiful, from *Exxon Valdez* to Fukushima Daiichi to the *Deepwater Horizon*.[217] Of course, one way to combat both the

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215 *E.g.*, VACLAV SMIL, ENERGY AT THE CROSSROADS: GLOBAL PERSPECTIVES AND UNCERTAINTIES 121 (2003) ("[M]ore than 100 years of long-term forecasts of energy affairs . . . have, save for a few proverbial exceptions confirming the rule, a manifest record of failure.").

216 *See supra* Part III.B.

217 *See generally* Bradley C. Bobertz, *Legitimizing Pollution Through Pollution Control Laws: Reflections on Scapegoating Theory*, 73 TEX. L. REV. 711 (1995); Robin Kundis Craig, *Legal Remedies for Deep Marine Oil Spills and Long-Term Ecological Resilience: A Match Made in Hell*, 2011 BYU L. REV. 1863 (2011); Lincoln L. Davies, *Beyond*

incompleteness of planning documents, as well as the near-certainty that plans will eventually need to change because they will mis-predict the future, is by implementing adaptive planning—an approach particularly well suited for rapidly changing circumstances such as those that may be presented by increasing, and increasingly severe, drought.[218] Nonetheless, there remains some risk that forcing utilities to include drought planning in their IRPs might distract from the fundamental purpose of that process, particularly if the need to plan for drought is marginal or the perceived risk of drought is greater than the reality.

D. Holistically Integrating Electricity and Water Planning

Finally, states could push utilities to holistically integrate electricity and water planning. What precisely this might look like would of course depend on the particular way jurisdictions implemented the idea. Nonetheless, there long have been calls to pull energy regulation out of its price- and supply-focused silo and integrate it with other areas of law, including environmental law.[219] Compelling utilities to broaden their planning processes to include other factors that are outside the traditional set of considerations they might assess—but that also directly impact them—would help break down these silos, at least to some degree.

This deeper integration of water and electricity planning might occur in several ways, each of which could elevate the IRP process into

Fukushima: Disasters, Nuclear Energy, and Energy Law, 2011 BYU L. REV. 1937; Lincoln L. Davies & Alexis Jones, *Fukushima's Shadow*, 48 VAND. J. TRANSNATIONAL L. 1083 (2015); Keith H. Hirokawa, *Disasters and Ecosystem Services Deprivation: From Cuyahoga to the Deepwater Horizon*, 74 ALB. L. REV. 543 (2011); Sanne Knudsen, *A Precautionary Tale: Assessing Ecological Damages After the* Exxon Valdez *Oil Spill*, 7 U. ST. THOMAS L.J. 95 (2009).

218 *See generally, e.g.*, Craig Anthony (Tony) Arnold, *Adaptive Watershed Planning and Climate Change*, 5 ENVTL. & ENERGY L. & POL'Y J. 417 (2010); Sadahisa Kato & Jack F. Ahern, "Learning by Doing": Adaptive Planning as a Strategy to Address Uncertainty in Planning, Landscape Architecture & Regional Planning Graduate Research and Creative Activity Paper 15 (2008), http://scholarworks.umass.edu/larp_grad_research/15 OR http://scholarworks.umass.edu/cgi/viewcontent.cgi?article=1000&context=larp_grad _research; Donald R. Nelson et al., *Adaptation to Environmental Change: Contributions of a Resilience Framework*, 32 ANN. REV. ENV'T & RESOURCES 395 (2007).

219 *See, e.g.*, Amy J. Wildermuth, *Is Environmental Law a Barrier to Emerging Alternative Energy Sources?*, 46 IDAHO L. REV. 509, 524, 528 (2010); Amy J. Wildermuth, *The Next Step: The Integration of Energy Law and Environmental Law*, 31 UTAH ENVTL. L. REV. 369, 388 (2011).

something more than an exercise in meeting (and/or reducing) demand. A state could, for instance, impose on utilities a requirement to identify, evaluate, and forecast all inputs to the supply-side of electricity generation, including water. Or, a state could mandate that utilities formally consult with water suppliers and regulators in the jurisdiction before an IRP will be approved.[220] Or, a state could require all energy producers, water suppliers, and sufficiently large water consumers to engage in a joint planning process similar to what IRPs are now doing for electricity alone. In short, there are myriad ways how IRPs could be expanded to integrate water planning more deeply.

Potentially, a variety of these paths could be combined to create an overall water-and-electricity planning process. The fact is that utilities already are heavily engaged in planning through the IRP process. At the same time, many states, including most states in the West, require water providers to engage in a planning process of their own.[221] By encouraging utilities and water planners to coordinate—and integrate—their planning processes, their evaluation of the needs of their system, and how to meet those needs, should become more complete. That is, the more that states facilitate, encourage, or require different planners from interrelated systems to talk to each other, the more likely it is that integrating planning will yield benefits.

Consequently, the benefits that might accrue from making electricity and water planning more holistic are likely contingent on how this integration occurs. A consultation requirement could produce some of the same planning synergy benefits as the other options outlined above, and perhaps to a greater degree. A more generic requirement that utilities look into and assess all the inputs into electricity production, however, might be less effective in terms of creating greater coordination among relevant players. Still, any version of greater integration of these types of planning is likely to produce some of the benefits the other options afford, including potentially conserving water, putting water to higher uses, shifting utilities' choice of generation and cooling technologies, and creating greater transparency and giving the public additional information. Perhaps most important, the more closely the planning of these systems is tied together, the more

220 The Energy Policy Act of 2005, for instance, mandates a similar kind of consultation process in the development of national interest electricity transmission corridors. 16 U.S.C. § 824p; *see* California Wilderness Coalition v. U.S. Dep't of Energy, 631 F.3d 1072 (9th Cir. 2011).

221 *See, e.g.*, ROBERT W. ADLER ET AL., MODERN WATER LAW: PRIVATE PROPERTY, PUBLIC RIGHTS, AND ENVIRONMENTAL PROTECTIONS 273–80 (2013).

effective and fruitful such changes in electricity and water planning are likely to be.

At the same time, no matter how integrated electricity and water planning become, there will be limits to what benefits such an integration might create. As with the option of mandating drought planning in IRPs, more integrated water and electricity planning does not guarantee any particular result. It simply requires further thought and consideration. Likewise, even if it is more integrated, planning is only as good as the information on which it relies. To the extent that information is faulty or limited, so too will the planning itself be. Thus, it may also be critical for both electricity and water planners not just to further integrate their planning efforts but also to continue to improve their data sources and to explore innovative methodologies, such as adaptive planning.[222] And, if more integrated planning does not result in better results, or more nimble utilities, the inevitable cost of pursuing a more integrated form of planning may not be worth it. Of course, none of these are, per se, arguments against integrating water and electricity planning more closely. They are, however, important caveats that bear careful consideration before a jurisdiction alters its process.

CONCLUSION

Drought is a persistent risk for the West, and that risk is only likely to increase in a climate change future. Shifts in water availability are almost certain to significantly impact electricity production in the region, from driving down hydroelectricity production and altering when it is available to impacting cooling of thermoelectric plants. Given this, one would expect that utilities already would be well ahead of the game, planning for future droughts and assessing how to adapt to them.

Our analysis shows that this is not the case. Integrated resource plans, quite simply, are incompletely integrated. Only a fraction of utilities currently assess water needs in their IRPs. Even fewer address the risk of drought in these documents, and fewer still actually develop plans in their IRPs to deal with potential drought. Thus, there is an important gap between the likely reality of the future West and what utilities are doing today to prepare for it.

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[222] *See supra* note 218 and accompanying text.

Jurisdictions have at their disposal numerous options for correcting these deficiencies, and different variations may be more optimal from one context to another. An easy starting place, however, is basic state law requirements that utilities assess water use, needs, and forecasts as part of their IRPs. Of the thirty-three IRPs we evaluated, virtually all those that looked at water were developed in states where this was a requirement. Thus, it is clear that such state mandates influence the IRP process, and other jurisdictions that should be worried about water availability may begin to strengthen their IRP process by adopting similar measures.

Of course, states and utilities need not stop at the IRP in how they improve their water and electricity planning processes. There are myriad other options for doing so, some of which we have outlined in Part IV of this Article. Notably, one particularly promising prospect is linking utility IRPs and state water planning processes. Connecting these processes might not only improve each of them individually, it might create synergies that encourage the two processes to evolve into something combined that is even greater than either process ever can be alone.

Indeed, by itself, simply integrating water and electricity planning more deeply through IRPs is unlikely to be a panacea. More should be done. But making water concerns a standard part of IRPs would be a step in the right direction—and it would not be a difficult one to take.

Each utility should evaluate water needs in its IRP, take those needs into account in choosing generation portfolios, and prepare for situations where water may not be available, or where the way in which it is available is different from the past. From there, further steps can, and should, be taken to tighten the nexus between electricity and water planning overall. But our analysis of recent IRPs in the West strongly suggests that this first step of integrating water into IRPs themselves is an important, and needed, place to start. In light of how critical both water and electricity are to the region, society should expect nothing less.