CHARGING ONWARDS: REMOVING BARRIERS TO ENERGY STORAGE IN RESTRUCTURED NEW ENGLAND STATES

INTRODUCTION

Unchecked climate change will have disastrous consequences for humanity and the global environment.[1] The world's current greenhouse gas (GHG) emissions pathway will likely lead to 3–4˚C of global warming.[2] That level of warming could make over half of all living species extinct, sink hundreds of coastal cities beneath the ocean, render parts of the Earth virtually uninhabitable, and kill billions of people.[3] Curbing climate change is imperative and requires substantial reductions in Carbon Dioxide (CO_2) emissions from burning fossil fuels.[4]

Replacing fossil-fuel power plants with zero-emission sources of renewable energy—such as wind and solar—is a cost-effective way to reduce CO_2 emissions.[5] Increasing the use of wind and solar energy will also reduce air pollution that kills tens of thousands of Americans every

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1. James Hansen et al., *Assessing "Dangerous Climate Change": Required Reduction of Carbon Emissions to Protect Young People, Future Generations and Nature*, 8 PLOS ONE 1, 5 (2013).

2. The standard projection is "four degrees of warming by the beginning of the next century, should we stay the present course." David Wallace-Wells, *The Uninhabitable Earth*, N.Y. MAG. (July 9, 2017), http://nymag.com/daily/intelligencer/2017/07/climate-change-earth-too-hot-for-humans.html. However, at least one analysis suggests that recent and continuing cost declines in solar and electric vehicle technology will likely limit global warming to 2.8–3.1˚C, even with weak climate policy. CARBON TRACKER INITIATIVE & GRANTHAM INST. CLIMATE & THE ENV'T, EXPECT THE UNEXPECTED: THE DISRUPTIVE POWER OF LOW-CARBON TECHNOLOGY 3, 34 (2017), https://www.carbontracker.org/reports/expect-the-unexpected-the-disruptive-power-of-low-carbon-technology/. If all countries also take the climate mitigation actions they pledged to do in their nationally determined contributions, such cost declines would likely limit global warming to 2.4–2.7˚C. *Id.*

3. Hansen et al., *supra* note 1, at 6–7; Wallace-Wells, *supra* note 2; Paddy Manning, *Too Hot to Handle: Can We Afford a 4-Degree Rise?*, SYDNEY MORNING HERALD (July 9, 2011), http://www.smh.com.au/environment/too-hot-to-handle-can-we-afford-a-4degree-rise-20110708-1h7hh#ixzz2LyOvFCeo (noting that possibly less than one billion humans could survive on an Earth that is 4˚C warmer).

4. *See* IPCC, Summary for Policymakers (2014), *in* CLIMATE CHANGE 2014: MITIGATION OF CLIMATE CHANGE: CONTRIBUTION OF WORKING GROUP III TO THE FIFTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE 10–12 (Ottmar Edenhoferet et al. eds., 2014) [hereinafter INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE], https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_frontmatter.pdf (prophesizing future mitigation pathways and the importance of reducing CO_2 emissions to promote sustainable development); *see* Hansen et al., *supra* note 1, at 1 (noting that CO_2 emissions from burning fossil fuels are the principal driver of climate change and arguing that humanity must reduce these emissions).

5. *See* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *supra* note 4, at 20 (discussing that using more renewable energy is a cost-effective way to reduce emissions); *Wind Explained: Wind Energy and the Environment*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/index.cfm?page=wind_environment (last updated Dec. 19, 2018) (stating that wind is a zero-emission source of energy); *Energy Explained: Solar Energy and the Environment*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/index.cfm?page=solar_environment (last updated Aug. 31, 2018) (stating that solar is a zero-emission source of energy).

year.[6] However, renewable energy sources are also intermittent sources of energy: they are only available when the sun shines or the wind blows.[7] Intermittency limits the share of electricity demand that wind and solar can feasibly meet without energy storage.[8] Thus, energy storage will play a key role in mitigating climate change.[9] Energy storage can also replace the most polluting power plants that only run when demand for electricity is at its highest.[10] Likewise, energy storage can help existing power plants to operate more efficiently, thereby reducing their emissions.[11] Energy storage thus provides numerous environmental benefits by reducing fossil-fuel emissions.[12]

Energy storage can make electricity cheaper by avoiding the need to build expensive new power lines and power plants to satisfy periods of high electricity demand.[13] In doing so, energy storage could collectively save consumers hundreds of millions of dollars annually.[14] Recognizing these benefits, the Federal Energy Regulatory Commission (FERC) recently promulgated Order 841 to enable energy storage to fairly compete with traditional power plants.[15] However, maximizing these savings—and the

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6. *See* Mark Z. Jacobson et al., *100% Clean and Renewable Wind, Water, and Sunlight (WWS) All-Sector Energy Roadmaps for the 50 United States*, 8 ENERGY & ENVTL. SCI. 2093, 2105, 2107 (2015) (asserting that converting to a 100% renewable energy system would save at least 45,800 American lives annually).

7. KEVIN B. JONES ET AL., THE ELECTRIC BATTERY: CHARGING FORWARD TO A LOW-CARBON FUTURE 9 (2017).

8. *Id.* This is not to say electric grids cannot accommodate significant amounts of renewable energy without storage. *Id.* at 122. In practice, grid operators have successfully integrated renewable energy by using traditional power plants that can alter their output on demand to compensate for fluctuating renewable output. *Id.* at 9. Most analyses indicate that existing grids can handle intermittent renewable generation providing 25–40% of the electricity supply on average. *Id.* at 122. Still, integrating higher levels of intermittent renewables will probably require energy storage. *Id.* at 9, 122.

9. *Id.* at 4.

10. Janice Lin & Giovanni Damato, *How Storage Can Help Get Rid of Peaker Plants*, GREENTECH MEDIA (June 28, 2010), https://www.greentechmedia.com/articles/read/energy-storage-vs-peakers [hereinafter Lin & Damato].

11. MASS. DEP'T OF ENERGY RES. ET AL., STATE OF CHARGE: MASS. ENERGY STORAGE INITIATIVE 94–95 (2016), http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf.

12. *See id.* at 3 ("[E]nergy storage is an economically and technically viable solution for alleviating . . . environmental challenges . . . .").

13. JUDY CHANG ET AL., THE BRATTLE GRP., THE VALUE OF DISTRIBUTED ELECTRICITY STORAGE IN TEXAS: PROPOSED POLICY FOR ENABLING GRID-INTEGRATED STORAGE INVESTMENTS 9–11 (2014), http://files.brattle.com/files/7589_the_value_of_distributed_electricity_storage_in_texas.pdf.

14. *Id.* at 13; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 77 ("[T]he total value of storage over 10 years could be around $3.4 billion.").

15. *See* Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 83 Fed. Reg. 9580, 9582 (Mar. 6, 2018) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order 841] (explaining that the Order remedies how current wholesale electricity market rules meant for traditional resources unjustly and unreasonably limit the services energy storage resources can provide).

environmental benefits of energy storage—requires that energy storage projects receive payment both for the value of the power lines and the power plants they replace.[16] If energy storage projects only receive compensation for one and not the other, investors will build only a small fraction of the energy storage projects they otherwise would.[17]

However, most New England states have passed electricity restructuring statutes that create legal barriers to electric utilities owning or controlling both power plants and power lines.[18] This Note will show that—absent mechanisms that compensate non-utility energy storage projects for avoiding transmission and distribution (T&D) costs—these laws create significant legal barriers to energy storage projects receiving compensation for the full range of services they can provide.[19] Moreover, removing such state-level barriers to energy storage would greatly magnify the impact of Order 841.[20] Although Order 841 will enable 7,000 megawatts (MW) of energy storage deployment by itself, national deployment levels could reach 50,000 MW if states ensure energy storage projects receive compensation for all the benefits they offer.[21] State restructuring laws as currently written thus place significant constraints on energy storage economics that severely limit the amount of energy storage private actors can deploy.[22]

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16. CHANG ET AL., *supra* note 13, at 17.

17. *Id.* at 2.

18. *See, e.g.*, ME. REV. STAT. ANN. tit. 35-A, § 3204 (2018) (prohibiting investor-owned utilities that deliver electricity from owning non-nuclear power plants, except for those it needs to perform its delivery functions "in an efficient manner"); N.H. REV. STAT. ANN. § 374-F:1 (2018) (targeting "functional separation" of electricity delivery from electricity generation); MASS. GEN. LAWS ch. 164, § 1A (2018) (prohibiting utilities that deliver electricity from owning or controlling non-nuclear power plants).

19. *See infra* Part IV.B (explaining how the lack of mechanisms to compensate non-utilities for avoided T&D costs combined with restructuring laws create barriers to energy storage investment). Technically the *combination* of restructuring laws and the lack of such mechanisms create the barriers for energy storage. However, this Note will at times refer to such barriers as *restructuring barriers* for the sake of brevity. This Note's use of that term, however, should not be read as an implicit critique of restructuring or its goals.

20. ROGER LUEKEN ET AL., GETTING TO 50 GW?: THE ROLE OF FERC ORDER 841, RTOS, STATES, AND UTILITIES IN UNLOCKING STORAGE'S POTENTIAL 19 (2018), http://files.brattle.com/files/13366_getting_to_50_gw_study_2.22.18.pdf.

21. *Id.* Note that in the many states that have not restructured their electricity systems, the relevant barriers to energy storage receiving full compensation are of course not due to restructuring. *See id.* at 11 (highlighting other state-level barriers energy storage faces); JIM LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, ELECTRICITY REGULATION IN THE US: A GUIDE 18, 90 (2d. 2016) [hereinafter LAZAR & REGULATORY ASSISTANCE PROJECT STAFF], http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf (showing cartographically which states have and have not restructured).

22. CHANG ET AL., *supra* note 13, at 17 (noting that neither utilities nor independent investors can independently earn sufficient revenue to justify investing in enough storage to maximize system-wide benefits in a restructured state).

This Note will analyze these barriers and suggest ways that New England policymakers could remove them. First, Part I will detail the environmental benefits and economics of energy storage.[23] Second, Part II will provide an overview of electricity regulation and restructuring.[24] Third, Part III will show that current New England restructuring laws generally preclude utility ownership of energy storage projects that participate in wholesale electricity markets.[25] At the same time, non-utility energy storage projects cannot receive payment for the value they provide to the T&D system.[26] The current legal regime thus retards energy storage investment by preventing any single entity from monetizing the full value of energy storage.[27] Finally, Part IV will suggest potential statutory changes legislatures could make and regulatory actions public utility commissions could take to remove or bypass these barriers.[28] Specifically, legislatures could amend restructuring statutes to allow utility-owned energy storage to participate in wholesale electricity markets, subject to certain safeguards.[29] Legislatures or commissions could also enable a shared-ownership model in which utilities own an energy storage project's T&D attributes while a third party owns its generation attributes.[30]

I. ENVIRONMENTAL BENEFITS AND ECONOMICS OF ENERGY STORAGE

A. Reducing the Environmental Harms of Fossil Fuels

1. Climate Change and Other Environmental Harms of Burning Fossil Fuels

Failing to mitigate climate change will have devastating effects on the world.[31] Among other things, climate change causes more frequent and destructive forest fires, flooding, droughts, and heat waves.[32] These environmental impacts affect human health, leading to increased

23. *See infra* Part I (outlining the environmental and economic benefits of energy storage).

24. *See infra* Part II (providing background on electricity regulation and restructuring).

25. *See infra* Part III.A (explaining how New England restructuring laws generally preclude utility ownership of energy storage projects that participate in wholesale electricity markets).

26. *See infra* Part III.B (overviewing why non-utility energy storage projects cannot capture the value they provide to the T&D system).

27. *See infra* Part III.B (articulating how the current legal regime in restructured New England states produces underinvestment in energy storage).

28. *See infra* Part IV (discussing ways to remove the restructuring-created barriers to energy storage).

29. *See infra* Part IV.A (examining models which exempt utility-owned energy storage from restructuring restrictions).

30. *See infra* Part IV.B (discussing shared-ownership models for energy storage).

31. Hansen et al., *supra* note 1, at 15.

32. *Id.* at 6, 8.

malnutrition, disease, and even death.[33] Additionally, climate change destroys critical habitat for numerous plants and animal species.[34] Global warming of 2.9˚C could result in a mass extinction that kills over 50% of all current species.[35] Furthermore, warming beyond 2˚C would eventually trigger multi-meter sea level rise.[36] That amount of sea level rise would result in "the loss of hundreds of historical coastal cities worldwide with incalculable economic consequences, create hundreds of millions of global warming refugees from highly-populated low-lying areas, and thus likely cause major international conflicts."[37]

Higher levels of global warming would further intensify these impacts.[38] Some scientists believe that if global warming of 4˚C occurred, less than a billion humans could survive on Earth.[39] Such a level of warming could cause mass famine, economic collapse, and make large portions of the Earth effectively uninhabitable.[40] Yet the world is currently heading towards as much as 4˚C of global warming, absent additional action to curb climate change.[41]

GHG emissions—especially CO_2 emissions—from the burning of fossil fuels are the principal driver of climate change.[42] Furthermore, burning fossil fuels also emits significant air pollution that kills tens of thousands of Americans every year.[43] Additionally, certain methods of

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33. *Id.* at 8.

34. *Id.* at 7.

35. *Id.*

36. *Id.* at 6.

37. *Id.*

38. Manning, *supra* note 3.

39. *See id.* (implying that climate change would kill over 8 billion people, assuming a global population of 9 billion by 2050).

40. *Id.*; Wallace-Wells, *supra* note 2.

41. Wallace-Wells, *supra* note 2; *but see* CARBON TRACKER INITIATIVE & GRANTHAM INST. CLIMATE & THE ENV'T, *supra* note 2, at 34 (projecting that even with weak climate policy cost declines in solar and electric vehicle technology would limit global warming to about 3˚C).

42. Hansen et al., *supra* note 1, at 1–2. The three most significant fossil fuels are coal, oil (petroleum), and natural gas. *See Fossil Fuels Still Dominate U.S. Energy Consumption Despite Recent Market Share Decline*, U.S. ENERGY INFO. ADMIN. (July 1, 2016), https://www.eia.gov/todayinenergy/detail.php?id=26912.

43. Jacobson et al., *supra* note 6. These air pollutants include sulfur oxides (SO_X), nitrogen oxides (NO_X), particulates, and—in the case of coal—heavy metals such as mercury. *Sulfur Dioxide Basics*, EPA, https://www.epa.gov/so2-pollution/sulfur-dioxide-basics (last visited Apr. 14, 2019); *Basic Information About NO_2*, EPA, https://www.epa.gov/no2-pollution/basic-information-about-no2 (last visited Apr. 14, 2018); *Coal Explained: Coal and the Environment*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/index.cfm?page=coal_environment (last visited Apr. 14, 2019). However, one should note that burning natural gas produces far less air pollution than burning coal or oil. *See Environmental Impacts of Natural Gas*, UNION OF CONCERNED SCIENTISTS, http://www.ucsusa.org/clean-energy/coal-and-other-fossil-fuels/environmental-impacts-of-natural-gas#.WhpyakqnFPY (last visited Apr. 14, 2019) ("[T]he combustion of natural gas produces negligible

extracting fossil fuels have significant environmental and human health impacts.[44] Therefore, reducing fossil fuel use both reduces pollution-related mortality and helps stem climate change.[45]

The burning of fossil fuels in power plants is the second largest source of CO_2 emissions in the U.S., emitting almost as much CO_2 as all fuels Americans burn for transportation.[46] Replacing fossil-fuel power plants with zero-emission renewable energy sources—like wind and solar—is a cost-effective way to reduce such emissions.[47] Limiting global warming to less than 2˚C requires zero-emission and low-emission energy sources to produce at least 80% of the world's electricity by 2050.[48] Currently such sources only provide 30% of the world's electricity.[49] Energy storage can provide substantial climate and pollution reduction benefits by enabling more renewable energy and helping fossil-fuel power plants to operate more efficiently.[50] Indeed, "electricity storage has been called the 'holy grail' for an economy-wide transition to low-carbon, renewable energy sources."[51]

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amounts of sulfur, mercury, and particulates. Burning natural gas does produce nitrogen oxides (NOX), which are precursors to smog, but at lower levels than gasoline and diesel used for motor vehicles.").

44. For example, Mountaintop Removal (MTR) mining for coal deforests mining regions, buries headwater streams under mining debris, and "contaminate[s] surface and groundwater with carcinogens and heavy metals." Paul R. Epstein et al., *Full Cost Accounting for the Life Cycle of Coal*, 1291 ANNALS N.Y. ACAD. SCI. 73, 77 (2011). Not surprisingly, researchers have associated MTR mining practices with cancer clusters. *Id.* Similarly, unconventional oil and gas wells that employ hydraulic fracturing pose numerous health risks to nearby communities. *Environmental Impacts of Natural Gas*, *supra* note 43. Hydraulic fracturing—or *fracking*—injects numerous chemicals and vast quantities of water underground to access unconventional sources of oil and gas. *Id.* If drillers improperly construct unconventional wells, they may contaminate local groundwater with fracking chemicals, naturally occurring radioactive materials, or underground gases. *Id.* Furthermore, improper disposal of fracking chemicals can contaminate surface water supplies. *Id.* Unconventional oil and gas wells may also emit hazardous air pollutants that cause "respiratory symptoms, cardiovascular disease, and cancer." *Id.*

45. Jacobson et al., *supra* note 6; *See* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *supra* note 4 (describing mitigation scenarios likely to slow climate change).

46. *Sources of Greenhouse Gas Emissions*, EPA, https://www.epa.gov/ghgemissions/ sources-greenhouse-gas-emissions (last visited Apr. 14, 2019).

47. *See* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *supra* note 4, at 20 (noting that using more renewable energy is a cost-effective way to reduce emissions); *see Wind Explained: Wind Energy and the Environment*, *supra* note 5 (noting that wind is a zero-emission source of energy); *Solar Explained: Solar Energy and the Environment*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/index.cfm?page=solar_environment (last updated Aug. 31, 2018) (noting that solar is a zero-emission source of energy).

48. INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *supra* note 4, at 10, 20.

49. *Id.* at 20.

50. *See* JONES ET AL., *supra* note 7, at 4 ("[T]he electric battery is a core climate solution."); MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11.

51. JONES ET AL., *supra* note 7, at 4.

2. How Energy Storage Can Curb Climate Change and Air Pollution

Energy storage[52] can reduce the environmental harms of climate change and conventional pollution in numerous ways. Most notably, it can enable electric grids[53] to integrate much higher levels of renewable energy sources, such as wind and solar.[54] It can also replace inefficient and disproportionately polluting *peaker* power plants.[55] Furthermore, it reduces the need for fossil-fuel power plants to inefficiently *ramp*—i.e., quickly change how much electricity they generate—and can thus reduce fuel use and emissions from existing power plants.[56]

Wind and solar energy are now cheaper on average than electricity from new fossil-fuel power plants.[57] Indeed, in many cases building new wind and solar power plants is now cheaper than continuing to run existing coal power plants.[58] However, their intermittent nature still limits their full potential because wind and sunlight are not available on demand.[59] Yet the nature of electricity requires consumers to use it at virtually the same

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52. *Energy storage* in its broadest sense refers to any system that stores energy for later use. For its purposes, however, this Note uses the term to refer to technologies such as batteries and flywheels, which can convert electricity into another form of energy and then convert that energy back into electricity at a later time. *See, e.g.*, *Energy Storage Technologies*, ENERGY STORAGE ASS'N, http://energystorage.org/energy-storage-1 (last visited Apr. 14, 2019).

53. An electrical grid is the sum of all interconnected electrical infrastructure that produces, transports, and delivers electricity in a given region. It includes everything from large centralized power plants to rooftop solar panels to the switchboxes in individual homes, as well as the millions of miles of wires that link it all together. *Electricity Explained: How Electricity is Delivered to Consumers*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/index.cfm?page=electricity_delivery (last updated Aug. 31, 2018).

54. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 98–102.

55. Lin & Damato, *supra* note 10; *Flexible Peaking Resource*, ENERGY STORAGE ASS'N, http://energystorage.org/energy-storage/technology-applications/flexible-peaking-resource (last visited Apr. 14, 2018); MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 47. Peaker or peaking power plants are power plants which the grid uses to meet peak demand and levels of demand near it. Robert Rapier, *The Load Following Power Plant: The New Peaker*, TRANSFORM (June 21, 2017), https://www.ge.com/power/transform/article.transform.articles.2017.jun.load-following-power-plant. Peak demand in turn refers to the maximum amount of instantaneous demand for power in a given period of time. *Demand for Electricity Changes Through the Day*, U.S. ENERGY INFO. ADMIN. (Apr. 6, 2011), https://www.eia.gov/todayinenergy/detail.php?id=830.

56. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 78, 86.

57. LAZARD, LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS-VERSION 12.0, at 2, 7 (2018), https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

58. *Id.* at 6; *see also* CARBON TRACKER INITIATIVE, POWERING DOWN COAL: NAVIGATING THE ECONOMIC AND FINANCIAL RISKS IN THE LAST YEARS OF COAL POWER 24 (2018), https://www.carbontracker.org/wp-content/uploads/2018/12/CTI_Powering_Down_Coal_Report_Nov_2018_4-4.pdf (estimating that the cost to continue operating as much as 70% of U.S. coal-generation capacity now exceeds the cost of building new renewable generation capacity).

59. JONES ET AL., *supra* note 7, at 9.

moment that a power plant generates it.[60] Consequently, the traditional "grid still relies on constant generation that is responsive to demand and available at the precise moment of that demand."[61] Intermittency is thus "the single biggest obstacle to powering our homes, businesses, and even the grid with renewable generation."[62]

Energy storage is the key to integrating large amounts of intermittent renewable energy.[63] For practical purposes, the ability to store energy and send it back onto the grid when necessary means the aggregate output of power plants does not always have to exactly and instantaneously match the end-use demand for electricity.[64] Energy storage systems can charge during periods when there is excess renewable generation and discharge that energy when the grid needs it most.[65] Energy storage therefore removes—or at least substantially alleviates—the limits intermittency impose on renewables' contribution to our electricity supply.[66] That in turn will reduce fossil fuel use and emissions.[67]

Energy storage's ability to replace peaker plants is another way it can reduce fossil fuel emissions.[68] Peaker plants run infrequently and they tend to be the least efficient—and the most polluting—power plants.[69] Thus, when energy storage systems charge during off-peak periods and discharge during peak periods, they can substantially reduce emissions of both CO_2 and conventional air pollutants.[70] This may be true even if the source of the

60. *Id.* at 6.

61. *Id.* at 9.

62. *Id.* at 9. This is not to say electric grids cannot accommodate significant amounts of renewable energy without storage. *Id.* at 122. In practice, grid operators have successfully integrated renewable energy by using traditional power plants that can alter their output on demand to compensate for fluctuating renewable output. *Id.* at 9. Most analyses indicate that existing grids can handle intermittent renewable generation providing 25–40% of the electricity supply on average. *Id.* at 122. Still, integrating higher levels of intermittent renewables will probably require energy storage. *Id.* at 9, 122.

63. *Id.* at 9.

64. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at i.

65. JONES ET AL., *supra* note 7, at 10. For simplicity, this Note uses the terms *charge* to mean *store energy* and *discharge* to mean *release energy*, regardless of whether or not the energy storage system in question is a battery.

66. *Id.* at 9.

67. *See* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *supra* note 4, at 20 (noting that using more renewable energy is a cost-effective way to reduce fossil fuel use and emissions).

68. *Id.* at 23.

69. *Flexible Peaking Resource*, *supra* note 55.

70. *See* Lin & Damato, *supra* note 10 ("For example, assuming Pacific Gas and Electric's base load electric mix as the off-peak source of electricity, energy storage would provide 55% CO_2 savings, 85% NOx savings, and up to 96% savings of CO per MWh of on-peak electricity delivered.").

off-peak energy is a baseload fossil-fuel power plant,[71] though the benefit is even greater if the source is a renewable power plant.[72]

However, such *peaker replacement* only reduces emissions when the off-peak source of electricity is not coal.[73] Consequently, in those parts of the U.S. where coal power plants provide off-peak electricity, deploying energy storage without also deploying renewable energy would increase emissions.[74] Fortunately, New England has very little coal generation; it accounts for only 1% of generation, while renewables account for 18.6% (counting hydroelectric), nuclear for 30%, and natural gas for 49%.[75] Furthermore, in New England, coal plants generally act as peaker plants, and thus energy storage would likely displace coal generation.[76] As such, even with the current generation mix, displacing peaker plants with energy storage in New England would reduce emissions.[77]

Finally, energy storage also lowers GHG and other emissions by reducing the need for fossil-fuel power plants to ramp.[78] Currently, a portion of fossil-fuel power plants need to constantly change their output levels in order to balance changes in demand or renewable generation.[79] However, most fossil-fuel power plants have an optimal output level at

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71. Baseload power plants "are the production facilities used to meet some or all of a given region's continuous energy demand, and produces energy at a constant rate, usually at a low cost relative to other production facilities available to the system." *Energy Dictionary: Baseload Plant*, ENERGY VORTEX, https://www.energyvortex.com/energydictionary/baseload_plant.html (last visited Jan. 23, 2019) [https://web.archive.org/web/20180723073034/https://www.energyvortex.com/energydictionary/baseload_plant.html].

72. Lin & Damato, *supra* note 10.

73. *See* Naga Srujana Goteti et al., *How Much Wind and Solar Are Needed to Realize Emissions Benefits From Storage?*, SPRINGER LINK (Dec. 11, 2017), https://link.springer.com/article/10.1007%2Fs12667-017-0266-4 (analyzing a coal-heavy grid and a relatively coal-free grid and finding energy storage decreased emissions in the latter but increased emissions in the former); *see id.* ("Storage increases carbon emissions when it enables a high emissions generator, such as a coal plant, to substitute for a cleaner plant, such as natural gas.").

74. *See id.* (stating that deploying energy storage in the coal-heavy Midcontinent ISO grid "will not be carbon neutral until wind or solar power reach around 18% of the [region's] generation capacity").

75. *Resource Mix*, ISO NEW ENG., https://www.iso-ne.com/about/key-stats/resource-mix/ (last visited Apr. 14, 2018).

76. *See id.* ("Coal- and oil-fired resources also make valuable contributions . . . when demand is very high or major resources are unavailable."); MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 41 ("Storage can also reduce the overall energy system emissions by reducing the time oil and coal generators are utilized to meet peak demand, particularly in winter.").

77. *See* MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at xi (calculating that in Massachusetts deploying the economically optimal level of energy storage would reduce "GHG gas emissions by more than 1 MMT CO2e over a 10 year time span" and equates "to taking over 223,000 cars off the road").

78. *Id.* at 86.

79. *Id.* at 92; JONES ET AL., *supra* note 7.

which they are most fuel-efficient.[80] Necessarily, such power plants operate less efficiently when they have to frequently change output levels.[81] Energy storage can perform this balancing role, often much more effectively than fossil-fuel power plants.[82] Therefore, energy storage can enable existing fossil-fuel power plants to operate at or close to their optimal levels more often, thereby reducing their emissions.[83] By the same token, energy storage can also remove the need to build fossil-fuel power plants specifically to balance increasing levels of intermittent renewables.[84]

B. The Economics of Energy Storage

1. The Economic Benefits of Energy Storage for Consumers

Energy storage can reduce the cost of operating electric grids, thereby making electricity cheaper for consumers.[85] This is especially true when an energy storage system can avoid the need for new transmission[86] and distribution[87] infrastructure in addition to providing wholesale electricity market services.[88] For example, the Brattle Group[89] calculates that deploying an efficient level of energy storage could reduce the net cost of operating the Texas grid by about $300 million per year.[90] The Massachusetts Department of Energy Resources (DOER) has likewise calculated that an investment of approximately $970 million to $1.4 billion in energy storage would save $3.4 billion over ten years.[91] Over $2 billion

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80. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 94.

81. *Id.*

82. JONES ET AL., *supra* note 7, at 125–26.

83. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11.

84. *Id.* at ii.

85. *Id.* at 88.

86. Transmission refers to the infrastructure "that moves bulk electricity from the generation sites over long distances to substations closer to areas of demand for electricity," or to the service such infrastructure provides. *Transmission & Distribution*, PJM LEARNING CTR., https://learn.pjm.com/electricity-basics/transmission-distribution.aspx (last visited Apr. 14, 2019).

87. Distribution refers to the wires and supporting infrastructure that carry electricity from the point of connection with the transmission system to the homes and businesses that consume the electricity, or to the service such infrastructure provides. *See id.* (creating an analogy that describes distribution).

88. CHANG ET AL., *supra* note 13, at 17.

89. The Brattle Group is an economic and financial consulting firm that has expertise in energy matters. *See About*, BRATTLE GRP., http://www.brattle.com/about (last visited Apr. 14, 2019) (explaining the function of the Brattle Group). Oncor Electric Delivery Company, a Texas utility, commissioned them "to explore the economics of grid-integrated storage deployment in Texas." CHANG ET AL., *supra* note 13, at 1.

90. CHANG ET AL., *supra* note 13, at 12.

91. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at xi.

of those savings would flow to Massachusetts's electricity consumers.[92] However, achieving such optimum benefit levels requires energy storage systems to receive revenue both from participating in electricity markets and from providing value to transmission or distribution systems.[93]

2. How Energy Storage Can Provide Value to the Grid and Revenue to Investors

Energy storage systems can provide wholesale electricity market services.[94] Wholesale electricity markets encompass the generation side of the electricity system, providing revenue to power plants for: (1) generating electricity; (2) being able to generate it when needed; and (3) helping to control power quality and providing reserves to maintain grid stability.[95] In New England,[96] the respective market categories for each of these services are: (1) the energy markets;[97] (2) the forward capacity market;[98] and (3) the ancillary service markets.[99] Energy storage systems are capable of providing all these services; however, from a practical standpoint, energy storage systems participate in the first market by arbitraging rather than generating electricity.[100]

Energy storage can also reduce the need for new transmission or distribution infrastructure.[101] Just as electrical reliability requires sufficient generating capacity to satisfy peak demand, a grid must also have sufficient

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92. *Id.* at 88.

93. CHANG ET AL., *supra* note 13, at 17; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 115, 117–19.

94. CHANG ET AL., *supra* note 13, at 2.

95. *Administering the Wholesale Electricity Markets*, INDEP. SYS. OPERATOR NEW ENG., https://www.iso-ne.com/about/what-we-do/three-roles/administering-markets (last visited Apr. 14, 2019).

96. In this Note, New England means the six states of Maine, Massachusetts, Rhode Island, Connecticut, New Hampshire, and Vermont.

97. The energy markets consist of the day-ahead and real-time energy markets. The former "allows market participants to secure prices for electric energy the day before delivery and to hedge against price fluctuations that occur in real time." *Administering the Wholesale Electricity Markets*, *supra* note 95. The latter "balances the dispatch of generation and demand resources to meet the instantaneous demand for electricity throughout New England." *Id.*

98. The forward capacity market "ensures the system has sufficient resources to meet the future demand by paying resources to be available to meet the projected demand for electricity three years out and operate when needed once the capacity commitment period begins." *Id.*

99. Ancillary services comprise a miscellaneous set of functions, including frequency regulation (rapidly changing generation output up or down to keep the grid balanced), providing reserves to compensate for unexpected power plant outages or spikes in demand, maintaining the voltage of the grid, and re-energizing the grid following a blackout. *Id.*; JONES ET AL., *supra* note 7, at 125–27.

100. JONES ET AL., *supra* note 7, at 124–27.

101. *Id.* at 127–28; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 7, at 115.

T&D infrastructure to transport enough electricity to meet peak demand.[102] Consequently, increases in peak demand have traditionally required construction of additional T&D infrastructure that the grid only uses during peak hours.[103] However, strategically placed energy storage systems can substitute for such infrastructure by charging during off-peak hours—making use of existing infrastructure when it is underutilized—and discharging during peak hours to relieve the strain on T&D systems.[104] This allows energy storage systems to substitute for *both* a peaker plant and the infrastructure that would otherwise carry electricity from that peaker plant to consumers.[105]

Providing wholesale market services and avoiding T&D costs each comprise significant portions of the potential value of energy storage systems.[106] In Texas, for example, the Brattle Group calculated that avoided T&D costs and associated reliability benefits accounted for 30–40% of energy storage's value.[107] The other 60–70% came from providing wholesale market services.[108] Conversely, in Massachusetts, the ratio is the opposite: DOER calculates that avoided T&D costs account for about 60–70% of the potential value to a project owner.[109] Providing wholesale market services accounts for the other 30–40%.[110] Regardless, either piece constitutes at least 30% of the total value.

This is significant because if energy storage projects cannot capture either value stream then the amount of energy storage deployment will drop dramatically. For example, in 2014, the Brattle Group calculated that the optimal level of storage in Texas is 5,000 MW when accounting for both value streams.[111] However, if investors can only capture one value stream,

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102. JONES ET AL., *supra* note 7, at 127–28; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 115.

103. JONES ET AL., *supra* note 7, at 127–28; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 115.

104. JONES ET AL., *supra* note 7, at 127–28; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 115.

105. *See* MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 121 (providing an example of how an energy storage system can reduce both peak demand and avoid transmission costs).

106. CHANG ET AL., *supra* note 13, at 2; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 117–19.

107. CHANG ET AL., *supra* note 13, at 2.

108. *Id.*

109. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 119. However, most of the *consumer* savings come from cost reductions on the wholesale market or generation side. *Id.* at 87.

110. *Id.*

111. CHANG ET AL., *supra* note 13, at 2, 11–12. More precisely, this is the optimal level of energy storage assuming the average cost of building a system is $350 per kilowatt-hour (kWh) of storage capacity. *Id.* at 2. If system costs fall below that price, the optimum level of storage would presumably increase. For context, 2018 costs for lithium-ion batteries directly integrated into the grid

they would only build about 1,000 MW of energy storage—just 20% of the optimum level.[112] The Brattle Group later extrapolated these findings to the entire U.S.[113] Nationally, compensating energy storage for all value streams could lead to 50,000 MW of energy storage, as opposed to just 7,000 MW if energy storage could only participate in wholesale markets.[114] In other words, allowing investors to capture all value streams could increase energy storage deployment more than sevenfold.[115]

This leads to the crux of the problem this Note seeks to address: the general inability of investors to capture all of an energy storage project's generation, transmission, and distribution value in restructured electricity markets.[116] States that have restructured their electricity markets restrict the ability of entities that provide distribution services to also provide wholesale market services.[117] In doing so, such states create barriers to energy storage projects capturing both value streams.[118]

II. ELECTRICITY REGULATION AND RESTRUCTURING

In the U.S., both the federal government and the states share regulatory authority over electricity.[119] As a general rule, the federal government regulates wholesale electricity sales and transmission while states regulate distribution and retail sales.[120] Traditionally, primarily state-regulated and

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ranged from $277 to $544 per kWh, depending on system size and configuration. LAZARD, LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 4.0, at 10, 13 (2018), https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf. Lazard predicts lithium-ion battery project costs to fall another 28% on average in the next five years. *Id.* at 14.

112. CHANG ET AL., *supra* note 13, at 8 (showing graphically that the money private investors could make from energy storage from wholesale markets alone would only justify building 1,000 MW of energy storage); *see id.* at 12 (indicating graphically that avoided T&D costs alone would not even justify building 1,000 MW of energy storage).

113. Lueken et al., *supra* note 20, at 19.

114. *Id.*

115. *Id.* Note, however, that the sevenfold increase may depend on removing other state level barriers as well. *See id.* at 11 (indicating that states may need to provide stable rate design and further clarify regulatory treatment of energy storage, particularly energy storage paired with renewables, to unlock its full potential).

116. *See infra* Part III.A (discussing how New England restructuring statutes limit the ability of energy storage projects to capture all of their project's generation, transmission, and distribution value).

117. *See* Amy L. Stein, *Distributed Reliability*, 87 U. COLO. L. REV. 887, 957–58 (2016) (explaining how restructuring restricts utility ownership of generation assets that provide wholesale market services).

118. *See id.* at 958 (highlighting problems with restricting utility ownership of generation assets).

119. JOSEPH P. TOMAIN & RICHARD D. CUDAHY, ENERGY LAW IN A NUTSHELL 385 (3d ed. 2017).

120. *Id.*; Federal Power Act, 16 U.S.C. § 824(b)(1) (2012). Technically, the Federal Power Act only gives the federal government jurisdiction over *interstate* transmission and wholesale sales. *Id.*

vertically integrated utilities provided most Americans with electricity.[121] As such, the entire electric industry from generation to distribution was subject to a complex system of rate regulation.[122] However, in the 1990s, federal regulatory changes enabled substantial competition in wholesale electricity generation.[123] At the same time, many states—especially in New England—enacted restructuring laws to introduce retail competition.[124] To help establish a level and competitive playing field, these laws also prohibited or restricted utilities from owning generators.[125] The current regulatory regime in most of New England thus separates the generation and distribution of electricity, to the detriment of energy storage.[126]

A. Traditional Utilities and Regulation

Vertically integrated electric utilities—entities that generate, transmit, and ultimately distribute electricity to retail ratepayers[127]—served most Americans prior to the 1980s.[128] Such utilities were monopolies that operated in state-defined exclusive service territories.[129] Electric utilities are "natural monopolies," as the economies of scale in building electrical grids makes it wasteful for competing firms to duplicate such infrastructure.[130] Consequently, society minimizes electricity costs by having a single firm

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However, "[t]he accepted view today is that any transmission or sale of electric energy within the interconnected United States is in 'interstate commerce,' even if the transaction's contractual origin and destination are within a single state." SCOTT HEMPLING, REGULATING PUBLIC UTILITY PERFORMANCE: THE LAW OF MARKET STRUCTURE, PRICING AND JURISDICTION 393 (2013). Consequently, "all wholesale sales and unbundled transmission service are subject to the Federal Power Act—unless they occur within Alaska, Hawaii, or the majority of Texas that is not interconnected with other states." *Id.*

121. HEMPLING, *supra* note 120, at 72.

122. *See infra* Part II.A (explaining utility rate regulation).

123. *See infra* Part II.B (discussing federal electricity regulation reforms in the 1990s).

124. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 18 (identifying states that adopted restructuring); HEMPLING, *supra* note 120, at 75 (mentioning the possibility of retail markets due to restructuring).

125. *See generally* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 10, 90 (noting how restructuring laws in many states required utilities to divest their power plants); *see, e.g.*, 39 R.I. GEN. LAWS § 39-1-27(d) (2018) (prohibiting utilities from owning generators).

126. *See infra* Part II.B (discussing the effects of restructuring and federal regulatory changes in New England); *see generally* Stein, *supra* note 117, at 958 (outlining the various routes that states have taken to address distribution and generation).

127. Retail ratepayers or simply ratepayers are utility customers, i.e., people and businesses who buy electricity from utilities for their own use. *See Definition of Ratepayer*, MERRIAM-WEBSTER, https://www.merriam-webster.com/dictionary/ratepayer (last visited Apr. 14, 2019) ("[A ratepayer is] one who pays for a utility service and especially electricity according to established rates.").

128. HEMPLING, *supra* note 120, at 72.

129. *Id.*

130. RICHARD F. HIRSH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM 17–18, 20 (1999).

build and operate the electric grid in a given area.[131] Even today, utility monopolies continue to provide distribution service.[132] However, monopolies also have the power to charge unreasonably high prices, as they lack competitors by definition.[133] States, therefore, established public utility commissions[134] to regulate the rates that utilities may charge to check their monopoly power.[135]

Commissions have a statutory duty to ensure that rates are "just and reasonable."[136] A commission must balance consumer and utility investor interests in order to set just and reasonable rates.[137] Thus, a commission must ensure that ratepayers do not pay exploitative or otherwise excessive prices.[138] However, rates must also be high enough to provide utilities with revenue to recover their operating and capital costs, and earn a reasonable return on their investments.[139] Returns are just and reasonable if they are "commensurate with returns on investments in other enterprises having corresponding risks" and are "sufficient to assure confidence in the financial integrity of the enterprise."[140] The just and reasonable standard

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131. *Id.*

132. HEMPLING, *supra* note 120, at 75.

133. HIRSH, *supra* note 130, at 27.

134. The precise name states give such bodies vary. For example, New Hampshire calls its regulator the Public Utilities Commission, while Massachusetts calls its regulator the Department of Public Utilities. N.H. REV. STAT. ANN. § 363:1 (2018); MASS. GEN. LAWS ch. 25, § 1 (2018). This Note uses the terms public utility commissions, utility commissions, or just commissions to refer to all such entities generically.

135. *Id.* at 21–23, 26–27. FERC is the federal analogue that regulates interstate transmission and interstate wholesale sales of electricity. Federal Power Act, 16 U.S.C. § 824(a) (2012); *What FERC Does*, FERC, https://www.ferc.gov/about/ferc-does.asp?csrt=16689007847031614432 (last updated Aug. 14, 2018). The Federal Power Act defines the "sale of electric energy at wholesale" as "a sale of electric energy to any person for resale." § 824(d). Consequently, FERC has jurisdiction over the rates a power plant selling electricity for resale in interstate commerce charges. It does not, however, have jurisdiction over the rates a vertically integrated utility charges its ratepayers for the electricity its own power plants generate.

136. HEMPLING, *supra* note 120, at 216.

137. Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944). In this case the Supreme Court was ruling on "the validity under the Natural Gas Act . . . of a rate order issued by the Federal Power Commission." *Id.* at 593. However, the term "just and reasonable" has the same meaning under federal and state law. HEMPLING, *supra* note 120, at 216. Thus, the content of the Federal Power Commission's (now FERC's) duty and state commission's duty to ensure just and reasonable rates is the same. *Id.*; *History of FERC*, FERC, https://www.ferc.gov/students/ferc/history.asp (last visited Apr. 14, 2019); *see also* Appeal of Pub. Serv. Co. of N.H., 547 A.2d 269, 271 (N.H. 1988) ("In setting rates, a regulatory commission follows a process of identifying consumer and producer interests competing for recognition, with an ultimate goal of striking a fair balance . . . that may be described as just and reasonable both to the customer and to the utility.").

138. HEMPLING, *supra* note 120, at 220–21.

139. *Hope Nat. Gas Co.*, 320 U.S. at 603.

140. *Id.* This requirement also has a constitutional dimension. HEMPLING, *supra* note 120, at 221. Utility regulatory statutes legally obligate utilities "to serve all customers in [their] service

also provides commissions with discretion in setting rates, as many potential rates could provide utilities with a reasonable return without gouging ratepayers.[141] As a consequence, all rates that fall within a "zone of reasonableness" are just and reasonable.[142] Furthermore, commissions are free to choose any methodology they wish to establish rates, so long as the end result is just and reasonable.[143]

Yet despite this discretionary authority, most utility commissions use a largely standardized process to set rates known as "rate of return" rate-making.[144] First, "the regulatory commission considers the annual expenses of the utility, capital investments the utility has made, and a range of returns achieved by utilities and other businesses with similar risk profiles."[145] The commission then uses this data to determine the utility's revenue requirement: the total amount of money a utility must collect to cover its expenses and earn a fair return.[146] The commission then allocates costs to customers and designs rates that enable a utility to collect its revenue requirement.[147]

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territory," and "maintain infrastructure sufficient to provide . . . service" to prescribed quality standards. *Id.* at 14, 34, 44. This constitutes a taking for the purposes of the Fifth and Fourteenth Amendments that requires just compensation, as "[s]hareholder investment in the utility is 'private property.'" *Id.* at 221. The revenue a utility collects from its authorized rates provides the compensation. *Id.* That compensation is only just, however, if a utility's rates provide it with "the opportunity to earn a fair return." *Id.* (quoting Missouri *ex rel.* Sw. Bell Tel. Co. v. Pub. Serv. Comm'n of Mo., 262 U.S. 276, 290 (1923) (Brandeis, J., concurring)). Consequently, "[r]ates which are not sufficient to yield a reasonable return . . . are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment." Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 690 (1923). However, in practice this constitutional requirement does not impose any additional constraints on commissions. *Hope Nat. Gas Co.*, 320 U.S. at 607. Any rate low enough to be unconstitutional would also not be just and reasonable; therefore a just and reasonable rate is constitutional. *See id.* ("Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.").

141. HEMPLING, *supra* note 120, at 220–21.

142. *Id.*

143. *See Hope Nat. Gas Co.*, 320 U.S. at 603 (stating that only the end result of a rate matters when determining if it is just and reasonable); *see also* HEMPLING, *supra* note 120, at 230 ("Both the 'just and reasonable' standard and *Hope's* focus on 'end result' lead to the same place: regulatory discretion over method selection.").

144. Inara Scott, *Teaching an Old Dog New Tricks: Adapting Public Utility Commissions to Meet Twenty-First Century Climate Challenges*, 38 HARV. ENVTL. L. REV. 371, 381–82 (2014).

145. *Id.*

146. HEMPLING, *supra* note 120, at 217.

147. Scott, *supra* note 144, at 382. The regulatory processes for allocating costs and designing rates are complex and beyond the scope of this Note. Readers interested in the details of such processes should see JONATHAN A. LESSER & LEONARDO R. GIACCHINO, FUNDAMENTALS OF ENERGY REGULATION 175–268 (2d ed. 2013).

A utility's revenue requirement has two components: operating expenses and capital expenses.[148] Operating expenses include all ongoing costs including depreciation, i.e., the cost of gradually recovering a utility's investment expenditures.[149] In contrast, capital expenses provide the "*return* on the firm's undepreciated capital investment, called the *rate base*."[150] In principle, utilities only make a profit on what is in their rate base, as they merely recover operating expenses.[151] Furthermore, the more investments they include in their rate base, the more profit they make.[152] However, commissions may bar a utility from including imprudent investments in its rate base, and likewise prevent the utility from recovering imprudently incurred operating expenses.[153] Such "[p]rudence review is regulation's substitute for competitive forces" as it allows commissions to protect ratepayers from paying unreasonable expenditures that a prudent competitive business would not incur.[154]

Utility rate regulation is complex,[155] but for this Note's purposes, only a few points are material. First, in the past, vertically integrated monopolies generated, transmitted, and distributed electricity to consumers.[156] Second, utility commissions price-regulated this entire value chain under rate-of-return ratemaking.[157] Third, utility commissions have discretion to choose any ratemaking methodology they wish, so long as the resulting rates are

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148. LESSER & GIACCHINO, *supra* note 147, at 63.

149. *Id.* at 63, 67.

150. *Id.* at 63. Capital expenses also include "an allowance for *working capital*, which is the amount of money a firm needs to have on hand every day to pay its bills." *Id.*

151. In practice, a utility can make a profit on the operating side if operating expenses unexpectedly decline after a commission sets its rates for a given period. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 88 (explaining how "regulatory lag" works, leading one to infer how a utility can still make a profit due to this phenomenon). Due to the "regulatory lag" between when costs change and a commission sets new rates, a utility can then collect more in rates than it needs to cover its operating costs. *Id.* (defining the term "regulatory lag" as the "time between the period when costs change for a utility, and the point when the regulatory commission recognizes these changes by raising or lowering the utility's rates to consumers").

152. *See* LESSER & GIACCHINO, *supra* note 147, at 49 (noting that utilities can artificially increase their rates through excessively investing in equipment).

153. *Id.* at 48. A utility's investments or costs are prudent only if a utility's decision to make or incur them was reasonable, considering industry norms and what the utility knew at the time. HEMPLING, *supra* note 120, at 236–37. However, a utility's "operating and investment decisions are typically considered prudent unless proven otherwise." LESSER & GIACCHINO, *supra* note 147, at 48. Consequently, regulators bear the burden of establishing imprudence. *Id.* However, commissions may also disallow recovery for prudent but uneconomic investments on the separate basis that they are not "used and useful." *See* HEMPLING, *supra* note 120, at 251–56 (discussing cost disallowance under the used and useful standard and its limits).

154. HEMPLING, *supra* note 120, at 235.

155. LESSER & GIACCHINO, *supra* note 147, at 205.

156. HEMPLING, *supra* note 120, at 72.

157. Scott, *supra* note 144, at 381.

just and reasonable.[158] Fourth, regulated utilities—which continue to manage electricity distribution even today[159]—make their profits by earning a rate of return on the physical infrastructure in their rate base.[160]

B. Competition in Wholesale Generation and Restructuring

By the 1990s, the traditional view that electricity generation was a natural monopoly was falling out of favor with policymakers.[161] Seeking to create competitive wholesale electricity markets, Congress removed the main federal regulatory barriers to non-utility generation in the Energy Policy Act of 1992 (EPAct 1992).[162] The Act and subsequent regulatory actions also led to the creation of Independent System Operator New England (ISO-NE) to manage New England's regional transmission system and wholesale electricity markets.[163] Maine, New Hampshire, Massachusetts, Rhode Island, and Connecticut also enacted restructuring laws to enable retail electricity competition.[164] These developments created the current legal landscape for electricity in New England.[165]

In addition to removing restrictions on non-utility generators, the EPAct 1992 also sought to provide non-utility generators with access to the transmission system.[166] Thus, the Act gave FERC the authority to order transmission line owners to carry electricity "for others—generators and purchasers of wholesale power—at just and reasonable rates."[167] In 1996,

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158. HEMPLING, *supra* note 120, at 230.

159. *Id.* at 75.

160. LESSER & GIACCHINO, *supra* note 147, at 63.

161. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 9 ("Following developments in the structure of the telecommunications and natural gas industries . . . some states 'unbundled' the electricity-supply function from distribution, on the theory that only the wires (the fixed network system) constituted a natural monopoly, whereas the generation of power did not.").

162. Jeffrey D. Watkiss & Douglas W. Smith, *The Energy Policy Act of 1992—A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REG. 447, 447, 449, 464–65 (1993).

163. LESSER & GIACCHINO, *supra* note 147, at 54; *Our History*, INDEP. SYS. OPERATOR NEW ENG., https://www.iso-ne.com/about/what-we-do/history (last visited Apr. 14, 2019).

164. LESSER & GIACCHINO, *supra* note 147, at 75; *see generally* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 9–10, 18 (highlighting how in 1994, after England and Wales began restructuring, some states and regions, including New England, followed suit).

165. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 18, 21–22 (noting that most New England states are restructured as of 2010; that ISOs and RTOs arose because of FERC Order 888, and ISOs and RTOs—including ISO-NE currently exist).

166. Watkiss & Smith, *supra* note 162, at 449.

167. *Id.* Transmission lines are "bottleneck" facilities, as they are "essential for competition, controlled by the incumbent and not economically duplicable by competitors." HEMPLING, *supra* note 120, at 74. This gives the transmission-owning utility substantial market power over non-utility generators and consumers alike. LESSER & GIACCHINO, *supra* note 147, at 33. Even worse, a utility with its own generators might try to refuse access to its generation competitors or otherwise unfairly favor

FERC issued Order 888, requiring all transmission-owning utilities to offer transmission service to others under the same terms and conditions they provided to themselves.[168]

Order 888 also encouraged transmission-owning utilities to form voluntary organizations known as Independent System Operators (ISOs), to further foster wholesale competition.[169] When utilities form an ISO—or a similar entity known as a Regional Transmission Organization (RTO)[170]—the utilities transfer control over their individual transmission systems to the ISO or RTO in exchange for rates that provide cost recovery and a return on investment.[171] ISOs and RTOs also administer wholesale electricity markets in their regions.[172] ISO-NE is the RTO for nearly all of New England,[173] responsible for managing the region's transmission system and its wholesale electricity markets.[174]

In the context of these federal changes to promote wholesale competition, many states also began to restructure their electricity systems to introduce retail competition.[175] Retail competition allows ratepayers to choose from multiple generators or suppliers of electricity who compete against each other.[176] Ratepayers' traditional regulated utility continues to perform distribution and billing services.[177] Thus, in principle, the utility merely transports and delivers the electricity their ratepayers purchased from a third party, rather than selling electricity the utility generated

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itself. *Id.* Hence, federal policymakers determined that assuring non-utility access to the transmission system required regulatory intervention. HEMPLING, *supra* note 120, at 74.

168. HEMPLING, *supra* note 120, at 74–75.

169. LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 21.

170. *Id.* After ISOs had been operating for a few years, FERC "concluded that further refinements were needed to address lingering concerns about competitive neutrality and reliability." *Id.* FERC developed the RTO model as a refinement of the ISO model in response to these concerns. *Id.* at 21–22. In 1999, FERC issued Order 2000, which included standards for RTOs and encouraged, but did not require utilities to form them. *Id.*; HEMPLING, *supra* note 120, at 75. ISOs and RTOs are very similar; their differences do not matter for the purposes of this Note. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 21 (outlining the similarity between these two entities).

171. LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 21 (explaining that ISOs and RTOs need functional control of their respective transmission systems).

172. *See id.* (charting ISOs' and RTOs' attempts to neutralize wholesale electricity markets).

173. *See* Allco Fin. Ltd. v. Klee, 861 F.3d 82, 93 (2d Cir. 2017) (noting that ISO-NE's jurisdiction encompasses "Connecticut, Massachusetts, Vermont, New Hampshire, Rhode Island, and most of Maine"). ISO-NE began as an ISO when it was founded in 1997. *Our History*, *supra* note 163. It became an RTO in 2005, but did not change its name. *Id.*

174. *Our Three Critical Roles*, INDEP. SYS. OPERATOR NEW ENG., https://www.iso-ne.com/about/what-we-do/three-roles (last visited Apr. 14, 2019).

175. HEMPLING, *supra* note 120, at 75; *see* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 18.

176. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 18 (detailing electricity supply options for consumers in restructured states).

177. *See id.* (outlining billing services under restructuring).

itself.[178] That said, restructured states also allow distribution utilities to provide "default supply" or "default service" to ratepayers who do not or cannot choose a competitive supplier.[179] However, restructured states still require distribution utilities to competitively source the electricity they use to supply default service.[180]

Restructured states generally require utilities to divest their generators, or at least functionally separate their distribution service from generation.[181] The rationale behind this is twofold. First, doing so *deregulates* generation, as it means power plants are no longer subject to rate regulation.[182] This eliminates the problems rate regulation of generation poses, such as potentially requiring ratepayers to pay for uneconomic power plants.[183] Second, it helps create a level playing field for competition by taking away the utility's incumbent advantage.[184] States in turn expect increased competition to decrease costs for consumers.[185] Unfortunately, barring utility involvement in generation also creates barriers for energy storage, as it means utilities cannot capture all of energy storage's value streams.[186]

178. *See generally id.* at 18–19 (highlighting the general principles of restructured states and how distribution and billing work in such states).

179. *Id.* at 18, 73. In fact, in restructured states most residential and small business customers remain on default service. *Id.* at 18.

180. *See id.* at 91 (explaining how distribution utilities buy power from "wholesale power supply markets" to supply default service); *see, e.g.*, N.H. REV. STAT. ANN. § 374-F:3(V)(c) (2018) ("Default service should be procured through the competitive market . . . .").

181. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 90 (highlighting how some restructured states have required utilities to divest from generation); *see, e.g.*, N.H. REV. STAT. ANN. § 374-F:3(III) ("Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services . . . .").

182. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 90 (noting that this divestment eliminates rate regulation of generation).

183. *Id.* at 90–91 ("[T]his eliminates . . . possible problems with gold-plating and cost-plus regulation in that segment (although it may cause other problems).").

184. *See, e.g.*, N.H. REV. STAT. ANN. § 374-F:1(I) (2018) ("[T]he development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry that will require . . . at least functional separation of centralized generation services from transmission and distribution services.").

185. *See, e.g.*, *id.* ("The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets.").

186. *See* Stein, *supra* note 117, at 958 ("Although requiring utilities to divest their generation assets facilitates more competition, it also . . . [creates barriers] . . . to multi-functioning resources like energy storage, whose value can only be fully realized where the user is able to capitalize on its multiple value streams.").

In sum, New England's current electricity system largely consists of non-utility generators competing in ISO-NE's wholesale markets,[187] ISO-NE managing the transmission system,[188] and traditional utilities providing physical distribution service.[189] Furthermore, all New England states (except Vermont) prohibit or restrict utility involvement in generation in order to promote competition.[190] As a result, restructuring has almost entirely eliminated the traditional vertically integrated utility model in the region.[191] Unfortunately, while restructuring requirements facilitate competition, they also create barriers to capturing the full range of benefits energy storage projects can provide absent further reforms.[192]

III. ENERGY STORAGE UNDER CURRENT NEW ENGLAND STATE LAWS

A. Current State Laws Regarding Distribution Utility Ownership of Energy Storage

1. Does Energy Storage Constitute Generation?

Restructuring laws restrict distribution utility ownership and control of generation assets.[193] As such, restructuring laws only limit distribution utility ownership of energy storage if energy storage constitutes generation.[194] Whether energy storage constitutes generation is not immediately clear.[195] Arguably, energy storage should logically qualify as generation if it acts as a generator by providing generation services.[196] Conversely, energy storage projects only store energy that some other

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187. *Administering the Wholesale Electricity Markets*, INDEP. SYS. OPERATOR NEW ENG., https://www.iso-ne.com/about/what-we-do/three-roles/administering-markets (last visited Apr. 14, 2019); *Our Three Critical Roles*, *supra* note 174.

188. *Our Three Critical Roles*, *supra* note 174; HEMPLING, *supra* note 120, at 75.

189. HEMPLING, *supra* note 120, at 75.

190. *See infra* Part III.A (discussing how current New England restructuring statutes restrict utility involvement in generation).

191. *See* Stein, *supra* note 117 (noting that areas that have restructured have broken up the traditional vertically integrated utility structure).

192. *See id.* at 958 (stating that while divesting generation assets may create more competition for utilities, it may impede multi-functioning).

193. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 90–91 (discussing what utilities have had to do under restructuring laws).

194. *See* Stein, *supra* note 117 (explaining the restrictions on utility ownership of energy storage when it constitutes generation in a restructured state).

195. *See* INDEP. SYS. OPERATOR NEW ENG., HOW ENERGY STORAGE CAN PARTICIPATE IN NEW ENGLAND'S WHOLESALE ELECTRICITY MARKETS 3 (2016), https://www.iso-ne.com/static-assets/documents/2016/01/final_storage_letter_cover_paper.pdf (noting that energy storage is a unique resource that can both supply and consume electricity).

196. *See id.* at 3–4 (stating that energy storage can provide generation services).

facility previously generated, and thus do not generate any *new* electricity.[197]

Nonetheless, energy storage projects—or at least those that participate in wholesale electricity markets—in all likelihood qualify as generation for the purposes of New England restructuring statutes.[198] Indeed, the Maine Public Utility Commission (MPUC) has recently implied that it considers energy storage to qualify as generation for the purposes of Maine's restructuring statute.[199] Additionally, as of this writing, ISO-NE has determined that energy storage may only receive full compensation for wholesale services if it participates as a generator in wholesale electricity markets.[200] To the extent that an energy storage project is participating or seeks to participate in New England wholesale electricity markets as a

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197. *See* JONES ET AL., *supra* note 7, at 124 ("Energy market opportunities for storage technologies involve . . . purchasing energy (and recharging batteries) when system marginal costs are low and then selling energy back to the system (discharging the batteries) when system marginal costs are high.").

198. *See* Order at 12, *In re* Emera Me. Request for Approval of Hampden Microgrid Project, No. 2017-00027 (Me. Pub. Util. Comm'n June 16, 2017), 2017 WL 2691245 [hereinafter Emera Order] (stating that the while this issue has not been address by the Commission, the MPUC implies that energy storage may qualify as generation).

199. *See id.* (referring to the battery in a proposed utility-owned, solar-plus-storage system "as a source of backup generation" while considering whether Maine's restructuring statute allows a utility to own such a system).

200. *See* INDEP. SYS. OPERATOR NEW ENG., *supra* note 195, at 4 (stating that energy storage may only participate in all wholesale markets as a generator). Note, however, that FERC's recent Order 841 requires all ISOs and RTOs to develop new participation models that compensate energy storage projects for "all capacity, energy, and ancillary services that [they are] technically capable of providing." Order 841, 83 Fed. Reg. 9580, 9582 (Mar. 6, 2018). Such participation models must also recognize "the unique characteristics of electric storage resources," specifically "their ability to both inject energy to the grid and receive energy from it." *Id.* at 9583, 9589. Yet despite this, ISO-NE's proposed Order 841 implementation plan requires energy storage systems "to register as generation resources." Peter Maloney, *As Grid Operators File FERC Order 841 Plans, Storage Floodgates Open Slowly*, UTIL. DIVE (Dec. 11, 2018), https://www.utilitydive.com/news/as-grid-operators-file-ferc-order-841-plans-storage-floodgates-open-slowly/543977/. FERC may ultimately require ISO-NE to change this aspect of its plan, though it is also possible FERC may allow ISO-NE to treat energy storage as a non-traditional form of generation. *See id.* (suggesting requiring energy storage to register as generation does not comply with Order 841); *but see* Order 841, 83 Fed. Reg. at 9583 ("[E]xisting participation models designed for *traditional* generation . . . do not recognize electric storage resources' unique physical and operational characteristics . . . ." (emphasis added)). Furthermore, even if FERC does require ISO-NE to change this aspect of its implementation plan, it would not matter for energy storage's status under state law if other states follow the MPUC's lead. *See* Emera Order, *supra* note 198 (referring to an energy storage system "as a source of . . . generation"). Notably, the MPUC interpreted Maine's restructuring statute as restricting the entities which could provide generation services. *See id.* at 11 ("At its core, the Restructuring Act was intended to open generation services to market forces . . . . It is through this prism which the generation ownership prohibition must be viewed."). Thus, if other commissions follow this services logic, they might preclude utility ownership of any energy storage project that provided wholesale market services on the basis that such utilities would then be impermissibly providing generation services.

generator, it would presumably constitute generation under New England state restructuring laws.[201] These laws therefore restrict utility ownership of energy storage projects that act as a generator.[202] The following Subsections will analyze how the individual restructuring laws of each restructured New England state affect utility-owned energy storage.[203]

2. Rhode Island

When Rhode Island restructured its electricity system, it statutorily required distribution utilities to transfer their generation assets to either an affiliate or an unrelated company.[204] It prohibited distribution utilities "from owning, operating, or controlling generating facilities" once they completed their restructuring plans.[205] However, Rhode Island allowed its public utilities commission to exempt certain utilities from its restructuring statute.[206] The Commission can only exempt a utility if it did not sell or distribute electricity outside the Commission's service territory prior to restructuring, and if it sells or distributes less than 5% of the electricity consumed in Rhode Island.[207] Thus, large utilities cannot own or operate energy storage projects that act as generators.[208] Small utilities can build and operate energy storage projects if they convince the Commission to exempt them.[209]

The Commission's authority to exempt small utilities from the restructuring statute has little practical significance, however, as a single

201. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 90 (stating that restructuring laws require utilities to divest generating assets).

202. This Note uses *act as a generator* and similar phrases as shorthand for participate in New England wholesale electricity markets as a generator or otherwise provide generation services.

203. *See infra* Parts III.A.2–6 (analyzing how the restructuring statutes of Rhode Island, Massachusetts, Maine, Connecticut, and New Hampshire impact utility-owned energy storage in each respective state).

204. 39 R.I. GEN. LAWS § 39-1-27(a)–(b) (2018). However, Rhode Island did allow its regulatory commission to exempt some distribution utilities from the requirement to *transfer* their existing generation assets under Section 39-1-27(a). *Id.* § 39-1-27(g). Nonetheless, it did not allow the Commission to exempt utilities from Section 39-1-27(d)'s prohibition on distribution utilities owning or operating generating assets. *Id.* § 39-1-27(d), (g). As such, the Commission cannot use Section 39-1-27(g) to allow a utility to build or acquire *new* generation assets, such as energy storage projects. *See id.* § 39-1-27(g) (setting forth requirements that the Commission must follow).

205. *Id.* § 39-1-27(d).

206. *Id.* § 39-1-2(5), (26) (2018).

207. *Id.* § 39-1-2(26).

208. *See id.* § 39-1-27(d) (barring utility ownership or control of generating facilities).

209. *See id.* § 39-1-2(26) (allowing the Commission to exempt small utilities that distribute less than 5% of the electricity consumed in the state).

distribution utility, National Grid, currently serves 99% of the State.[210] As such, National Grid cannot qualify for this exception.[211] Thus, Rhode Island effectively prohibits distribution utility ownership of generation in 99% of the State.[212] By extension, Rhode Island effectively prohibits utility ownership of energy storage projects that provide wholesale generation services throughout virtually the entire State.

3. Massachusetts

Massachusetts outright prohibits distribution utility ownership of all non-nuclear generation.[213] When it implemented restructuring, Massachusetts statutorily required its distribution utilities to either sell their non-nuclear generation assets or transfer them to an independent affiliate.[214] Massachusetts's restructuring statute now bars a distribution utility from "directly owning, operating, or controlling . . . [non-nuclear] generating facilities."[215] Instead, the statute requires utilities to restructure by separating their distribution and generation businesses into independent affiliates to maintain "strict separation between such generation affiliate and the distribution and transmission operations of such electric company."[216] As such, a distribution utility in Massachusetts can neither own a non-nuclear generating asset nor participate in operating the non-nuclear generation asset of an affiliate.[217] As energy storage is non-nuclear, Massachusetts prohibits distribution utility ownership of energy storage projects that act as generators.[218]

4. Maine

Maine's restructuring statute generally requires investor-owned distribution utilities to divest all non-nuclear generation assets located in the U.S.[219] The statute prohibits investor-owned utilities from owning or

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210. *Learn About Electricity*, STATE OF R.I. OFF. ENERGY RESOURCES, http://www.energy.ri.gov/electric-gas/electricity/learn-about-electricity.php (last visited Apr. 14, 2019).

211. *See* 39 R.I. GEN. LAWS § 39-1-2(26) (allowing the Commission to only exempt small utilities).

212. *Learn About Electricity*, *supra* note 210.

213. MASS. GEN. LAWS ch. 164, § 1A(b)–(c) (2018).

214. *Id.*

215. *Id.* § 1A(b)(1).

216. *Id.* § 1A(c).

217. *Id.* § 1A(b)–(c).

218. *Id.*

219. ME. REV. STAT. ANN. tit. 35-A, § 3204(1) (2018).

controlling "generation or generation-related assets."[220] However, it also authorizes MPUC to allow an investor-owned distribution utility to own or control "generation and generation-related assets" under certain circumstances.[221] Specifically, the Maine statute authorizes MPUC to allow this if it finds that such ownership or control "is necessary for the utility to perform its obligations as a transmission and distribution utility in an efficient manner."[222]

An energy storage project that both acts as a generator and provides T&D benefits should arguably qualify under this exception.[223] A reasonable interpretation of performing T&D obligations "in an efficient manner" would be providing T&D service at the lowest possible net cost.[224] To the extent an energy storage project can earn revenue by acting as a generator, it effectively reduces the net cost of the project as a potential transmission or distribution asset.[225] Moreover, the energy storage project would *have* to act as a generator in order to minimize the net cost of the project.[226] Consequently, operating the energy storage project as a generator would be "necessary for the utility to perform its obligations . . . in an efficient manner."[227] Thus, MPUC could allow a utility to build and operate such an energy storage project if it is the cheapest option for meeting a particular transmission or distribution need.

Unfortunately, MPUC is unlikely to adopt such a reading of Section 3204(6).[228] To date, MPUC has interpreted Section 3204(6) "very narrowly."[229] Specifically, in *Central Maine Power Co.*, MPUC determined that "a fundamental purpose of the Restructuring Act was to prohibit [T&D] utilities from using generation or generation-related assets to

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220. *Id.* § 3204(5).

221. *Id.* § 3204(6).

222. *Id.*

223. *See id.* (authorizing the Commission to allow utility ownership of generation assets necessary for efficiently transmitting or distributing electricity).

224. *Id.*

225. *See* CHANG ET AL., *supra* note 13, at 17 (noting that wholesale market revenue can reduce the net cost to ratepayers of an energy storage project that provides T&D benefits); *see* MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 119 (clarifying that allowing utilities to capture wholesale market revenue would reduce the investment that would need to be included in a utility's rate base).

226. *See* MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 117–18 (arguing that energy storage must be used to provide multiple benefits in order to be cost-effective).

227. Order at 5, *In re* Cent. Me. Power Co., 234 Pub. Util. Rep. 4th (PUR) 170 (Me. Pub. Util. Comm'n May 4, 2004) (No. 2004-21) [hereinafter Cent. Me. Power Co. Order] (quoting ME. REV. STAT. ANN. tit. 35-A, § 3204(6)).

228. *See id.* (stating the Commission believes that Section 3204(6) does not allow distribution utilities to provide generation services).

229. Emera Order, *supra* note 198, at 8.

provide services to third-parties."[230] Thus, MPUC believes that Section 3204(6) was never intended to allow utilities to use generation within their systems for grid support, nor to provide generation services under any circumstances.[231] Yet any energy storage project acting as a generator would be providing generation services to third parties by definition.[232] Thus, MPUC interprets Section 3204(6) in a way that would *never* allow an investor-owned distribution utility to provide generation services.[233] In other words, Maine prohibits investor-owned distribution utilities from operating energy storage projects that act as generators.

However, Maine only prohibits *investor-owned* distribution utilities from owning generation.[234] Unfortunately, investor-owned utilities serve about 75% of Maine electricity customers and deliver about 79% of the electricity consumed in the State.[235] As such, this exception has limited significance, as it only applies to utilities that serve about a quarter of the State.[236] Therefore, in practice, Maine categorically prohibits distribution utilities from capturing the generation value of energy storage projects throughout the majority of the State.[237]

5. Connecticut

Connecticut law generally prohibits distribution utilities from owning or operating generation assets.[238] However, Connecticut law also provides several exceptions to this general rule.[239] Most importantly, if the State's Integrated Resource Plan (IRP) calls for new generation, Connecticut's Public Utilities Regulatory Authority (PURA) must solicit proposals for such generation.[240] A distribution utility may then submit proposals for

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230. Cent. Me. Power Co. Order, *supra* note 227, at 6.

231. *Id.* at 5.

232. *See* INDEP. SYS. OPERATOR NEW ENG., *supra* note 95, at 4 (defining *act* as a generator).

233. Cent. Me. Power Co. Order, *supra* note 227, at 4.

234. ME. REV. STAT. ANN. tit. 35-A, § 3204(5) (2018).

235. *See Delivery Rates*, MAINE: ME. PUB. UTIL. COMMISSION, http://www.maine.gov/mpuc/electricity/delivery_rates.shtml (last visited Apr. 14, 2019) (noting that investor-owned utilities serve 605,052 of the State's 809,239 total customers).

236. *Id.*

237. *See* ME. REV. STAT. ANN. tit. 35-A, § 3204(5) (prohibiting the investor-owned utilities that supply most of the State's electricity from owning generating assets).

238. CONN. GEN. STAT. ANN. § 16-244e(a) (2018).

239. *See id.* ("An electric distribution company shall not own or operate generation assets, except as provided in this section and sections 16-43d, 16-243m, 16-243u, 16a-3b and 16a-3c.").

240. *Id.* § 16a-3b(b). An Integrated Resource Plan is a plan that "[t]he Commissioner of Energy and Environmental Protection" develops "in consultation with the electric distribution companies" for meeting the State's electricity needs in the cheapest way possible that is "consistent with the state's environmental goals and standards." *Id.* § 16a-3a(a).

building new generation assets "on the same basis as other respondents to the solicitation."[241] Additionally, if PURA does not receive enough proposals to meet the IRP's goals, it may direct a utility company to make "a proposal to build and operate an electric generation facility in the state."[242]

Importantly, Connecticut law requires IRPs to identify generation, transmission, and distribution needs and determine how best to meet them.[243] More specifically, such plans must "assess and compare the cost of *transmission* line projects, new power sources, renewable sources of electricity, conservation and *distributed generation* projects to ensure the state pursues only the least-cost alternative projects."[244] Furthermore, such plans must also assess whether distributed generation projects can meet reliability needs *before* a utility may consider building new power lines.[245]

Connecticut allows a distribution utility to build and operate generation assets, provided that an IRP calls for new generating assets and the utility makes a competitive proposal.[246] Connecticut's IRP statute also contemplates distributed generation projects providing both generation services *and* avoiding transmission costs.[247] To the extent a distribution utility can own and operate distributed generation projects—because they are a type of generation asset—a distribution utility could also capture the benefits of any T&D costs such projects might avoid.[248] Thus, under certain circumstances, Connecticut allows a distribution utility to capture a generator's generation, transmission, and distribution value.[249]

Accordingly, Connecticut law does allow a distribution utility to own an energy storage project that acts as a generator under certain circumstances.[250] Specifically, a distribution utility could do so if the

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241. *Id.* § 16a-3b(b)(1). However, Section 16a-3b(b)(1) also requires a distribution utility to demonstrate "that its bid is not supported in any form of cross subsidization by affiliated entities," presumably to prevent it from unfairly underbidding non-utility proposals. *Id.*

242. *Id.* § 16a-3c(a).

243. *Id.* § 16a-3a(c).

244. *Id.* § 16a-3e (emphasis added).

245. *Id.*

246. *Id.* § 16a-3b(b).

247. *See id.* § 16a-3e (requiring IRPs to compare the costs of distributed generation with both transmission projects and other new power sources).

248. *See* MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 117–18 (providing an example of how a utility could use an energy storage project providing wholesale services to also avoid distribution costs).

249. CONN. GEN. STAT. ANN. § 16a-3b(b)(1) (allowing a utility to build generating assets if it submits a winning competitive proposal).

250. *See id.* § 16a-3b(b) ("When the Integrated Resources Plan contains an option to procure new sources of generation, the authority shall develop and issue a request for proposals."); *id.* § 16a-

State's IRP called for such an energy storage project and the distribution utility made a successful competitive proposal to build it.[251] Additionally, PURA could order a distribution utility to build such an energy storage project if no one submitted a proposal to build it.[252] The distribution utility would then capture the benefit of any avoided T&D costs the energy storage project might create.[253] As such, Connecticut allows a distribution utility to build and own an energy storage project, as well as capture its generation, transmission, and distribution value.

Connecticut is an outlier among restructured New England states because it now allows distribution utilities to potentially build and own *any* generation project in its IRP.[254] Indeed, this exception arguably swallows the general rule that "[a]n electric distribution company shall not own or operate generation assets."[255] Thus, distribution utilities in Connecticut can own energy storage projects that act as generators because Connecticut partially reversed restructuring when it added this exception in 2007.[256]

6. New Hampshire

New Hampshire's restructuring statute states that "generation services should be . . . at least functionally separated from transmission and distribution services."[257] Functional separation generally refers to "requiring utilities to separate their competitive generation functions from their regulated transmission and distribution functions."[258] It is "a less drastic alternative to divestiture, under which 'a utility would have to divest itself of all or a portion of its generating assets to another entity or entities

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3b(b)(1) ("[A]n electric distribution company may submit proposals in response to a request for proposals on the same basis as other respondents to the solicitation.").

251. *Id.*

252. *See id.* § 16a-3c(a) ("[I]f the Public Utilities Regulatory Authority does not receive and approve proposals sufficient to reach the goal set by the Integrated Resources Plan, the authority may order an electric distribution company to submit . . . a proposal to build and operate an electric generation facility in the state.").

253. Indeed, the IRP statute's policy would seem to favor placing an energy storage project in a location where it could substitute for new transmission projects. *See id.* § 16a-3e ("The Integrated Resources Plan . . . shall . . . assess the least-cost alternative to address reliability concerns, including, but not limited to, lowering electricity demand through conservation and distributed generation projects before an electric distribution company submits a proposal for transmission lines or transmission line upgrades . . . .").

254. *Id.* § 16a-3b(b)(1).

255. *Id.* § 16-244e(a).

256. 2007 Conn. Acts 1051 (Reg. Sess.).

257. N.H. REV. STAT. ANN. § 374-F:3(III) (2018).

258. *In re* Algonquin Gas Transmission, L.L.C., 186 A.3d 865, 878 (N.H. 2018) (Hicks, J., dissenting) (quoting Sonnet C. Edmonds, *Retail Electric Competition in Kansas: A Utility Perspective*, 37 WASHBURN L.J. 603, 632 (1998)).

in order to remain in the distribution business.'"[259] New Hampshire's Public Utilities Commission previously interpreted this statutory language as requiring functional separation and thus barring utility involvement in generation.[260]

However, in May 2018, the New Hampshire Supreme Court reversed the Commission's decision that interpreted this statutory language in *In re Algonquin Gas Transmission, LLC*.[261] It instead held that the statute does not require "'functional separation' of generation services from transmission and distribution services."[262] The Court explained that functional separation was one of just 15 interdependent and thus mutually qualifying restructuring policy principles the statute lists.[263] Furthermore, the statute did not "reflect any legislative intent that the 'functional separation' policy principle is meant to 'direct' the PUC in the exercise of its authority in implementing the chapter to the exclusion of the 14 remaining principles."[264] Therefore, the statute does not "require 'functional separation' in all circumstances."[265] Furthermore, the Court found "that the primary intent of the legislature" in enacting the restructuring statute "was to reduce electricity costs to consumers."[266] Thus, the *Algonquin* Court interpreted the state's restructuring statute as authorizing the Commission to allow utility involvement in generation when doing so advances other restructuring policy principles that outweigh functional separation and reduces costs for consumers.[267]

But when and how other restructuring policy principles could outweigh functional separation is rather unclear, as 10 of the remaining 14 principles emphasize or incorporate the importance of fostering competition,[268] which

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259. *Id.* (quoting Edmonds, *supra* note 258, at 631).

260. *In re* Pub. Serv. Co. of N.H. d/b/a Eversource Energy, 333 Pub. Util. Rep. 4th (PUR) 163 (N.H. Pub. Utils. Comm'n Oct. 6, 2016), *rev'd In re* Algonquin Gas Transmission, L.L.C., 186 A.3d 865, 875 (N.H. 2018).

261. *Algonquin*, 186 A.3d at 874–75.

262. *Id.*

263. *Id.* at 873.

264. *Id.*

265. *Id.* at 874.

266. *Id.*

267. *See id.* at 874 n.4 (indicating that the Commission can authorize utility involvement in generation services when "other policy principles identified in the statute clearly outweighed functional separation and [doing so] would produce more reliable electric service at lower rates for New Hampshire consumers than presently exists without any significant adverse consequences").

268. *See* N.H. REV. STAT. ANN. § 374-F:3(II) (2018) ("Allowing customers to choose among electricity suppliers will help ensure fully competitive and innovative markets."); *id.* § 374-F:3(IV) ("Comparability should be assured for generators competing with affiliates of groups supplying transmission and distribution services."); *id.* § 374-F:3(V)(c) ("Default service should be procured through the competitive market . . . ."); *id.* § 374-F:3(VI) ("A nonbypassable and competitively neutral

is the purpose of functional separation.[269] Thus, insofar as violating functional separation undermines competition, violating the functional separation principle also undermines what many of the other principles try to achieve. Furthermore, even the statute's "rate relief" principle seems to rank competitive markets as equally if not more important than rate reduction.[270] It flatly states that "[t]he goal of restructuring is to create competitive markets," while also noting these markets are merely "*expected* to produce lower prices for all customers."[271] Thus in a principle-weighing analysis, the principle most relevant to reducing consumer costs cuts in both directions—and arguably more towards competition and functional separation. These points would logically weigh strongly against allowing a functional separation violation under the *Algonquin* principle-weighing test.

As a practical matter then, the *Algonquin* test makes it theoretically possible but extremely difficult for the Commission to authorize utility involvement in generation services and thus violate the functional separation principle.[272] *Algonquin* does at least establish that the restructuring statute does not automatically bar utilities from owning and operating energy storage projects that act as generators while also providing T&D benefits.[273] However, many of the restructuring statute's principles

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system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity."); *id.* § 374-F:3(VII) ("The rules that govern market activity should . . . ensure a fully competitive market."); *id.* § 374-F:3(VIII) ("Increased competition in the electric industry should be implemented in a manner that supports and furthers the goals of environmental improvement."); *id.* § 374-F:3(XI) ("The goal of restructuring is to create competitive markets . . . ."); *id.* § 374-F:3(XIII) ("New England Power Pool (NEPOOL) should be reformed and efforts to enhance competition and to complement industry restructuring on a regional basis should be encouraged."); *id.* § 374-F:3(XIV) ("The market framework for competitive electric service should, to the extent possible, reduce reliance on administrative process. New Hampshire should move deliberately to replace traditional planning mechanisms with market driven choice as the means of supplying resource needs."); *id.* § 374-F:3(XV) ("The commission should seek to implement full customer choice among electricity suppliers in the most expeditious manner possible . . . .").

269. *See* Ne. Energy Partners v. Mahar Reg'l Sch. Dist., 971 N.E.2d 258, 265 (Mass. 2012) (noting that functional separation is "a necessary first step in" implementing a fully competitive market for electricity generation); *Algonquin*, 186 A.3d at 878 (Hicks, J., dissenting) ("The importance of at least functionally separating generation services from transmission and distribution services is that achieving and maintaining a competitive market in generation services depends upon it.").

270. *See* N.H. REV. STAT. ANN. § 374-F:3(XI) ("The goal of restructuring is to create competitive markets that are expected to produce lower prices for all customers than would have been paid under the current regulatory system.").

271. *Id.* (emphasis added).

272. *See Algonquin*, 186 A.3d at 874 n.4 (indicating that other principles must outweigh the functional separation principle before the Commission could authorize a violation of the latter).

273. *See id.* at 874 (stating that the restructuring statute does not require "'functional separation' in all circumstances"); *id.* at 878 (Hicks, J., dissenting) (quoting Edmonds, *supra* note 258, at 632) (explaining that functional separation refers to "requiring utilities to separate their competitive generation functions from their regulated transmission and distribution functions").

lean in favor of competition and thus functional separation.[274] The Commission would thus find it difficult to authorize utility ownership of such energy storage projects.[275] The *Algonquin* decision will therefore be of little practical benefit to energy storage deployment.

Yet one other provision of the restructuring statute would seem to offer some hope for energy storage. This provision states that "distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs."[276] Indeed, a separate statute explicitly permits distribution utilities to "invest in or own distributed energy resources."[277] New Hampshire defines "distributed energy resources" as including energy storage projects connected to the local distribution systems that help reduce T&D costs.[278] Thus, though New Hampshire generally prohibits distribution utilities from operating generation,[279] it explicitly exempts distributed generation projects—including energy storage—that reduce T&D costs.[280]

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274. *See* N.H. REV. STAT. ANN. § 374-F:3 (listing these principles).

275. *See Algonquin*, 186 A.3d at 874 n.4 (indicating that other principles must outweigh the functional separation principle before the Commission could authorize a violation of the latter).

276. N.H. REV. STAT. ANN. § 374-F:3(III).

277. *Id.* § 374-G:4(I).

278. *Id.* § 374-G:2(I)(b).

279. *Id.* § 374-F:3(III).

280. *Id.* § 374-G:2(I)(b). Note, however, that though this Section clearly defines energy storage as a distributed energy resource, the Section is less clear on whether energy storage constitutes generation. Section 374-G:2(I)(b) in full states:

> 'Distributed energy resources' means electric generation equipment, including clean and renewable generation, energy storage, energy efficiency, demand response, load reduction or control programs, and technologies or devices located on or interconnected to the local electric distribution system for purposes including but not limited to reducing line losses, supporting voltage regulation, or peak load shaving, as part of a strategy for minimizing transmission and distribution costs as provided in RSA 374-F:3, III.

Id. Whether energy storage constitutes distributed "electric generation equipment" matters because many of the statute's restrictions on utility ownership apply only to distributed generation. *See, e.g.*, *id.* § 374-G:3–4 (limiting when a utility can own or invest in distributed generation). Conceivably, one might read Section 374-G:2(I)(b) as defining only "clean and renewable generation" as "electric generation equipment" such that energy storage is a "distributed energy resource" but not necessarily distributed generation. *Id.* § 374-G:2(I)(b). However, the lack of any semicolon separating "renewable generation" from "energy storage" indicates that the commas surrounding the phrase "including clean and renewable generation" are not internal commas. *See* BRYAN GARNER, THE REDBOOK: A MANUAL ON LEGAL STYLE 14 (3d ed. 2013) ("[S]emicolons . . . separate elements of a series of phrases or clauses if one or more of the elements contains an internal comma."). That indicates "energy storage," like "clean and renewable generation," is part of an "electric generation equipment" series rather than just part of a "distributed energy resources" series, which makes energy storage a form of "electric generation equipment." N.H. REV. STAT. ANN. § 374-G:2(I)(b). The cross reference further bolsters this conclusion, as the cross-referenced Section mentions using only "distributed *generation* resources as

However, New Hampshire severely limits the scope of this exception.[281] First, a utility can only use the electricity that distributed generation facilities produce to offset distribution system losses,[282] for its own use, or for a customer's use if the generator is sited on that customer's property.[283] This limits the amount of distributed generation utilities can own or control, and their ability to use such generation to reduce transmission charges.[284] This exhaustive list of authorized purposes also means a utility could not bid such a project into wholesale markets.[285] Second, utilities can only own or invest in distributed generation with a capacity of 5 MW or less.[286] This limits the potential economies of scale larger system sizes could provide.[287] Third, the combined capacity of all distributed generators that a utility either owns or invests in cannot exceed "[six] percent of the utility's total distribution peak load."[288] That inefficiently limits the peak load reductions distributed generation can provide.[289] Indeed, an efficient level of energy storage capacity alone—excluding all other distributed energy resources—would likely reduce peak demand by nearly 10%.[290]

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part of a strategy for minimizing transmission and distribution costs." *Id.* § 374-F:3(III) (emphasis added). As such, the most natural reading of the statute is that it defines energy storage as "electric generation equipment" and thus as distributed generation when it is "located on or interconnected to the local electric distribution system." *Id.* § 374-G:2(I)(b). Consequently, the statute's limitations on utility ownership of distributed generation most likely apply to energy storage. *See, e.g.*, *id.* § 374-G:3–4 (limiting when a utility can own or invest in distributed generation).

281. N.H. REV. STAT. ANN. § 374-G:3–4 (2018).

282. Distribution system losses refer to electricity lost in the distribution system for either technical reasons inherent in electricity distribution or commercial reasons. Jignesh Parmar, *Total Losses in Power Distribution and Transmission Lines*, ELECTRICAL ENGINEERING PORTAL (Aug. 19, 2013), http://electrical-engineering-portal.com/total-losses-in-power-distribution-and-transmission-lines-1. About 70% of total losses from both the T&D systems occur on the distribution system. *Id.* On average, 5% of electricity is lost as it travels from power plants to consumers in the U.S. *How Much Electricity is Lost in T&D in the United States?*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 (last updated Jan. 9, 2019). Consequently, distribution system losses only account for about 3.5% of the electricity a distribution utility handles. Offsetting such losses thus can only support a limited amount of distributed generation. *Id.*

283. N.H. REV. STAT. ANN. § 374-G:3(I)–(III).

284. *Id.*

285. *Id.*

286. *See id.* § 374-G:2(II) (excluding generators with a capacity of 5 MW or more from the definition of distributed energy resources).

287. *See* LAZARD, *supra* note 57, at 10 (implying that many efficiently sized energy storage projects on a distribution system would be about 10 MWs).

288. N.H. REV. STAT. ANN. § 374-G:4(II).

289. *See* MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 91 (asserting that an efficient level of energy storage would reduce peak load by nearly 10%).

290. *Id.*

Thus, though New Hampshire law explicitly allows utilities to invest in energy storage when it reduces T&D costs,[291] it effectively prohibits utilities from deploying what would likely be an efficient level of energy storage or bidding energy storage projects into wholesale markets.[292] Consequently, New Hampshire's restructuring and related statutes still significantly constrain energy storage development.[293]

B. Inability of Non-Utility Energy Storage Projects to Receive Compensation for Avoided T&D Costs

Restructuring statutes do not legally prohibit compensating non-utility generators for avoided T&D costs; they only restrict utility ownership of generators.[294] However, in all states "[p]hysical distribution, due to its natural monopoly characteristics, remains a monopoly service provided by traditional utilities."[295] Furthermore, ISO-NE charges distribution utilities for the costs of running the transmission system based on how much their ratepayers contribute to regional peak load.[296] Yet ISO-NE does not provide a mechanism that directly compensates independent non-transmission projects for reducing the need or substituting for new transmission investment.[297] Thus, distribution utilities are the only entity that can directly

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291. N.H. REV. STAT. ANN. § 374-G:2(I)(b).

292. *See id.* § 374-G:3–4 (limiting when a utility can own or invest in distributed energy resources and the purposes for which a utility can use distributed energy resources).

293. *Id.*

294. *See supra* Part III.A (discussing how New England restructuring statutes restrict utility ownership of generators).

295. HEMPLING, *supra* note 120, at 75.

296. INDEP. SYS. OPERATOR NEW ENG., § II: ISO NEW ENGLAND OPEN ACCESS TRANSMISSION TARIFF, at § II.21 (n.d.), https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf (last updated Jan. 29, 2019). Specifically, a distribution utility pays ISO-NE "an amount equal to its Monthly Regional Network Load for the month times the applicable Local Network RNS Rate." *Id.* § II.21.1. RNS stands for Regional Network Service, which is essentially ISO-NE's terminology for transmission service. *See id.* § II.11 ("Regional Network Service . . . includes transmission service . . . for the delivery to a Network Customer of its energy and capacity . . . ."). A utility's Monthly Regional Network Load is essentially the amount of power it draws from the regional grid during the hour of greatest region-wide power demand in a given month. *See id.* § II.21.2 ("[A] Network Customer's 'Monthly Regional Network Load' is its hourly load . . . coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ('Monthly Peak')."). This structure allows a utility to reduce its transmission service charges by reducing the power it draws from the regional grid during the monthly peak hour. *See id.* § II.21.1 (explaining that a distribution utility's transmission charge is proportional to its Monthly Regional Network Load).

297. *See id.* ATTACHMENT K REGIONAL SYSTEM PLANNING PROCESS § 3.5 (noting that ISO-NE only "account[s] for market responses" in its transmission planning process, differentiating market responses from transmission solutions, and indicating it will solicit only transmission solutions to meet reliability needs); ISO-NE defines "market responses" as "investments in resources (e.g., demand-side

benefit financially from reduced transmission costs.[298] Consequently, a non-utility energy storage project will only receive compensation for avoided T&D costs if a distribution utility pays it for providing such value.[299]

However, distribution utilities have no incentive to do so. Consistent cost savings proportionally reduce a utility's revenue requirements and the total amount of revenue it earns through rates.[300] Consequently, unlike competitive businesses, utilities operating under cost-of-service regulation have little financial incentive to reduce costs.[301] Moreover, distribution utilities only earn a return on their rate-base: the undepreciated value of their physical infrastructure and equipment, plus working capital.[302] If a third-party energy storage project removes the need for new distribution infrastructure, it reduces a distribution utility's rate base and thus, its total profits.[303] Such third-party energy storage projects work against a utility's

projects, generation and distributed generation);" energy storage would thus fall into this category. *Id.* Furthermore, ISO-NE will only "seek generation, demand-side and merchant transmission alternatives" when it is unable to find a viable transmission solution to meet a transmission system reliability need. *Id.* § 7.3(b)(i). Therefore, ISO-NE would solicit energy storage to meet a transmission reliability need "as a last resort," but would not directly compensate an energy storage project for helping to prevent a reliability need from arising. *Id.* § 7.3(a). However, ISO-NE's wholesale energy markets and Forward Capacity Market do provide higher payments to supply and demand resources in transmission-constrained areas. *See FAQs: Locational Marginal Pricing*, INDEP. SYS. OPERATOR NEW ENG., https://www.iso-ne.com/participate/support/faq/lmp (last visited Apr. 14, 2019) (explaining how local wholesale energy prices incorporate transmission system constraints); *About the FCM and Its Auctions*, INDEP. SYS. OPERATOR NEW ENG., https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-the-fcm-and-its-auctions (last visited Apr. 14, 2019) (outlining how the Forward Capacity Market pays more for resources in capacity-constrained zones). ISO-NE thus compensates non-transmission resources for relieving transmission constraints, thereby indirectly compensating such resources for avoiding some transmission costs. *FAQs: Locational Marginal Pricing*, *supra*; *About the FCM and Its Auctions*, *supra*.

298. Reduced transmission costs for the utility would indirectly result in lower rates for ratepayers. *See supra* Part II.A (discussing utility rate regulation).

299. *See* CHANG ET AL., *supra* note 13, at 17 (noting that independent investors do not have a way of financially benefiting from reducing a utility's T&D costs).

300. *See* LESSER & GIACCHINO, *supra* note 147, at 45–46, 63 (explaining that a regulated utility's revenue is proportional to its costs); *but see* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 87 ("However, the utility does still have some incentive to reduce expenses. Once the rates are set, they stay in place until changed, regardless of whether the operating expenses are the same, higher, or lower than in the test year; so the utility earns more if it incurs lower costs.").

301. Regulators do subject utility spending to prudence review and may prevent utilities from collecting money from customers to cover excessive spending. LESSER & GIACCHINO, *supra* note 147, at 48–49. As such, utilities still have some incentive to control costs in order to ensure regulators will allow them to recover costs. However, regulators presume that a utility's operating costs and investments are "prudent unless proven otherwise." *Id.* at 48. Consequently, prudence review provides utilities with a weaker incentive to control costs than market competition provides to competitive businesses.

302. *Id.* at 63–64.

303. *See id.* (highlighting that utilities make their profits by placing physical infrastructure in their rate base).

business interest, and therefore utilities will not willingly facilitate such projects.[304] They will not compensate third parties for removing the need for traditional distribution infrastructure unless regulators obligate them to do so.[305]

Currently, no such regulatory requirement appears to exist.[306] Granted, "some states have made reforms to open the distribution system to third-party products and services that enable consumers to buy less distribution service from [utilities]."[307] However, these reforms enable consumers to directly contract for certain energy services from third parties, and do not require utilities to compensate third parties for avoided costs.[308] The closest existing mechanism is a "Value of Solar" tariff, which in part requires utilities to compensate ratepayers who generate their own solar energy for any resulting avoided T&D costs.[309] However, as the name implies, such a mechanism only applies to solar, and no New England state has yet adopted such a tariff.[310] Moreover, the existing scholarly literature that discusses potential ways to compensate non-utilities for avoided T&D costs implicitly presumes no such general method currently exists.[311]

Under current New England state laws, non-utility energy storage projects appear to have no means to compel utilities to compensate them for the value of avoided T&D costs.[312] Though restructuring statutes do not limit the ability of these entities to earn revenue in wholesale electricity market, current New England regulatory regimes effectively prevent them

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304. *See id.* at 49 (noting that utilities may have a financial incentive to *gold-plate*, that is, invest in unnecessary infrastructure to artificially inflate their rate base and thus increase their allowed rates); LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 86 ("[T]he Averch-Johnson effect . . . suggests that utilities will spend too much on capital investments because their allowed return is a function of their investment.").

305. LESSER & GIACCHINO, *supra* note 147, at 49.

306. *See, e.g.*, Ari Peskoe, *Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar*, 11 TEX. J. OIL GAS & ENERGY L. 211, 292–96 (2016) (implying that no mechanism requiring utilities to compensate third parties for avoided T&D costs exists).

307. *Id.* at 287.

308. *See id.* at 287–88 (discussing such reforms in the context of third-party ownership of distributed solar-power systems).

309. *See id.* at 279 (explaining what a "Value of Solar" tariff is).

310. *See id.* (noting that only Minnesota and the city of Austin, Texas have adopted a "Value of Solar" tariff).

311. *See, e.g.*, *id.* at 292–96 (implying that no such mechanism currently exists).

312. *See, e.g.*, *id.* (implying that no such mechanism currently exists by describing the problems of the current system and suggesting ways policymakers *could* require utilities to compensate third parties for the value they provide to the grid).

from monetizing the full range of value energy storage provides.[313] Consequently, non-utilities lack the incentive to invest in and deploy an economically efficient level of energy storage in New England.[314] Because utilities also lack this incentive for the most part,[315] current New England regulatory regimes effectively guarantee that all types of electricity sector participants will underinvest in energy storage to the detriment of both consumers and the environment.[316]

IV. WAYS STATES CAN REMOVE BARRIERS TO ENERGY STORAGE

State policymakers have two main options for removing restructuring barriers to energy storage. First, states could enact new legislation simply exempting energy storage from the restrictions restructuring places on utility-owned generation.[317] Or second, policymakers could create a shared-ownership model in which a non-utility captures an energy storage project's wholesale market revenue, while a utility captures its T&D benefits.[318] This Part addresses the advantages and drawbacks of both options.

A. Exempt Energy Storage from Utility-Ownership Restrictions

The simplest solution would be to exempt energy storage from all restrictions restructuring places on utility ownership or operation of generators.[319] In principle, such an approach should minimize project development costs: utilities will know the most about where to locate an energy storage project to provide the greatest distribution or transmission cost savings.[320] However, it could also undermine restructuring, and

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313. *See supra* Part III.A (showing how New England restructuring statutes restrict utility ownership of generators); *see, e.g.*, Peskoe, *supra* note 306 (discussing that no commissions require utilities to compensate for avoided T&D costs exists).

314. *See, e.g.*, Peskoe, *supra* note 306, at 294–96 (demonstrating how declining to compensate third parties for the value their products and services provide to the grid hamstrings competitive development of energy storage and similar technologies).

315. *See supra* Part III.A (describing how New England restructuring statutes restrict utility owned energy storage projects from earning revenue in wholesale electricity markets).

316. *See* CHANG ET AL., *supra* note 13, at 17–18 (arguing that restructured electricity markets, as currently structured, lead to inefficiently low levels of energy storage deployment).

317. *See infra* Part IV.A (discussing how an energy storage exemption might impact storage deployment).

318. *See infra* Part IV.B (outlining how shared ownership models might function).

319. *See supra* Part III.A (describing the ways in which restructuring statutes restrict utility ownership of energy storage projects).

320. *See* Peskoe, *supra* note 306, at 294 (noting that utilities know more about their costs than anyone else); Stein, *supra note* 117, at 958–59 (arguing that utility ownership would reduce transaction costs as well as "minimize both coordination and visibility problems").

potentially provide utilities with a *de facto* monopoly over non-customer-owned distributed energy storage.[321]

A legislature would have to enact such a change because statutory language restricts utility ownership of energy storage projects that act as generators.[322] Generally, states could use language such as "notwithstanding [citation to state's restructuring statute], distribution utilities may own and/or operate energy storage projects that participate in wholesale electricity markets."

Such legislation would also have to address how a utility could rate base an energy storage project that acts as a generator, and how it would handle the revenue the project earns in wholesale electricity markets.[323] One option would be to allow a utility to rate base the entire cost of the project, but then use all revenue the project raises to reduce its customers' rates. Unfortunately, this approach places the risks of the project underperforming in wholesale markets on ratepayers.[324] It also arguably gives regulated utilities an unfair advantage on the wholesale electricity market.[325] Under this regime, utilities could potentially use ratepayer money to subsidize an energy storage project's participation in wholesale markets, bidding the project in at prices below what the utility needs to recover the project's costs.[326] A utility could thus exploit the benefits it enjoys as a regulated monopoly to undercut competitive generators in wholesale markets.[327] This is precisely why New England restructuring statutes restricted utility ownership of generating assets.[328] Consequently, such an approach could

321. *See supra* Part III.B (explaining that restructuring was meant to encourage competition and avoid risking ratepayer money on generating assets).

322. *See supra* Part III.A (overviewing the restrictions imposed by New England restructuring statutes on utility-owned energy storage projects).

323. *See* Lueken et al., *supra* note 20, at 11, 18 (noting that states need to define ways of valuing T&D benefits as well as accounting for the wholesale value of energy storage while avoiding conflicts between the two roles).

324. *See* LESSER & GIACCHINO, *supra* note 147, at 56 (highlighting that allowing a regulated utility to recover the cost of uncompetitive investments in rates shifts market risk from the utility to its ratepayers).

325. *See id.* at 71–72 (explaining how forcing ratepayers to *cross-subsidize* a utility's competitive activities unfairly hurts the utility's competitors).

326. *See id.* (emphasizing how cross-subsidies can result in ratepayers paying more, and how utilities can then use that ratepayer money to undercut their non-utility competitors).

327. *See id.* ("When a regulated firm provides several products or services, some that are regulated and some that are not, it is important to ensure that the nonregulated costs are not tagged with the regulated costs. Doing so . . . can nobble the firm's unregulated competitors . . . .").

328. *See, e.g.*, N.H. REV. STAT. ANN. § 374-F:1 (2018) (stating that restructuring is meant to create free and fair competitive markets, which require the separation of generation from T&D).

severely undermine the restructuring policy of fostering competition in electricity generation.[329]

A better option for states that wish to avoid this outcome would be to allow the utility to rate base only the value of the project's avoided distribution or transmission costs,[330] while allowing it to keep the wholesale market revenue. An example of such statutory language might be:

> A utility shall only recover the value of transmission and distribution system benefits and avoided costs of authorized and prudent utility-owned energy storage project(s) in its distribution rates as a component of rate base. The utility shall keep the portion of the income the energy storage investment earns from participation in wholesale electricity markets.

This places the business risks of the project underperforming in the wholesale markets on the utility, not its customers. It also prevents the utility from using ratepayer money to unfairly undercut other wholesale market participants. This approach thus provides greater consumer protection and is more in keeping with restructuring principles.[331]

Regardless of which approach to rate basing an energy storage project a state chooses, utility ownership would likely minimize costs and facilitate

329. *See, e.g.*, *id.* (pronouncing the goal of restructuring: to "harness[] the power of competitive markets").

330. Of course, either the state legislature or its utility commission would then need to determine how to calculate this value. *See* LESSER & GIACCHINO, *supra* note 147, at 69 (noting there are multiple ways to calculate the value of utility assets even when a utility rate bases the entire asset). A state could let a utility rate base the avoided cost of any other infrastructure the utility would have built but-for the energy storage project in a manner somewhat akin to a "[v]alue of service" approach. *See id.* ("Value of service is based either on a prior period of time . . . or on the projected value of the assets for a future regulatory period."). However, in the event that an energy storage project is much cheaper than traditional infrastructure—at least after subtracting wholesale market revenues from the project's cost—this could cause ratepayers to unjustly and unreasonably overpay for the project. *See* Appeal of Pub. Serv. Co. of N.H., 547 A.2d 269, 271 (N.H. 1988) (defining that rates are only just and reasonable if they fairly balance utility and consumer interests). A state could allocate more of the financial benefits of energy storage to ratepayers by limiting the utility to rate basing only a percentage of avoided costs. But such a blunt instrument may fail to adequately compensate marginal but still economically efficient energy storage projects and thus render them nonviable. *See* CHANG ET AL., *supra* note 13, at 17; MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 115, 117–19 (explaining that deploying an optimal level of energy storage requires adequately compensating energy storage projects for all the benefits they provide). A better approach might be to rate base the value of all avoided T&D costs, but then cap the total combined return a utility could make on an energy storage project, including revenue from wholesale markets and ratepayers. *See* LESSER & GIACCHINO, *supra* note 147, at 139–41 (overviewing how regulators determine a rate of return for utilities). The state could then require a utility to use any revenue in excess of the allowed rate of return to reduce customer rates.

331. *See supra* Part II.B (asserting that restructuring was meant to shield ratepayers from the costs of uneconomic generating assets as well as promote competition).

optimal siting of storage projects.[332] Having a utility, as a single integrated entity, handle such a project reduces transaction costs.[333] Utilities—unlike third parties and regulators—also have direct access to data about their distribution system and cost structure.[334] Therefore, they do not need to spend time or money acquiring such data from another source. A utility can thus optimize energy storage project siting to maximize T&D benefits more readily and efficiently than any other entity.[335] Monopoly utilities can also borrow money at lower interest rates than competitive businesses, which reduces the financing costs for an energy storage project.[336] In sum, these factors could make utility-owned energy storage quicker and cheaper to build than third-party owned energy storage.

However, such an approach would *de facto* leave energy storage in the hands of monopoly utilities.[337] With no mechanism for anyone else to monetize avoided T&D benefits, utilities would have an immense advantage over non-utility energy storage developers.[338] Even allowing a utility to partially rate base an energy storage project would significantly reduce the costs a utility needs to recover from wholesale markets.[339] In contrast, a non-utility developer would only be able to build projects that could be profitable with just wholesale market revenue.[340] That advantage could lead utilities' energy storage projects to crowd out other projects, destroying much of the market for non-utility energy storage.[341] State

332. *See* Stein, *supra* note 117, at 958, 960 (noting that utility ownership can avoid inefficiencies and high transaction costs); *id.* at 959 ("A new world of utility-owned [distributed energy resources] would minimize both coordination and visibility problems . . . .").

333. *Id.* at 958, 960.

334. *See* LESSER & GIACCHINO, *supra* note 147, at 38 ("From the regulator's perspective . . . the exact shape and location of the firm's average cost curve will be uncertain."); Peskoe, *supra* note 306, at 294 (noting that utilities know more about their own costs than anyone else).

335. *See* Stein, *supra* note 117, at 959 ("A new world of utility-owned [distributed energy resources] would minimize both coordination and visibility problems, as the utility would have as much knowledge about the resources as they would of their other, more traditional resources.").

336. HIRSH, *supra* note 130, at 23–24.

337. *Id.* at 23.

338. *See supra* Part III.B (overviewing why non-utilities cannot monetize avoided T&D costs under the current regulatory system).

339. *See* LESSER & GIACCHINO, *supra* note 147, at 71–72 (explaining how enabling a utility to recover the costs of an unregulated activity from ratepayers allows it to undercut its non-utility competitors).

340. *See supra* Part III.B (overviewing why non-utilities can only monetize wholesale market revenue under the current regulatory system).

341. LESSER & GIACCHINO, *supra* note 147, at 71–72. The lack of competition would also mean utility energy storage projects would not be subject to market pressures to control costs. *See* Matias Busso & Sebastian Galiani, *The Causal Effect of Competition on Prices and Quality: Evidence from a Field Experiment* 3 (Nat'l Bureau of Econ. Res., Working Paper No. 20054) (2018), https://www.nber.org/papers/w20054.pdf ("[T]he entry of new competitors leads to price reductions by putting more competitive pressure on market incumbents."). Such a lack of market pressure could offset

policymakers that wish to foster more competition in the electricity sector would also dislike this result.[342] Moreover, non-utility developers would likely oppose the passage of such legislation, thereby decreasing the chance a state could implement such a solution in the first place.[343]

Thus, exempting energy storage from restructuring limitations would likely lead to distribution utilities dominating energy storage deployment. This offers the benefits of simplicity, lower transaction and financing costs, and thus potentially faster and greater levels of energy storage deployment.[344] However, it could also put non-utility developers at a severe disadvantage and significantly curtail competition in energy storage.[345] Allowing distribution utilities to rate base projects that act as generators also violates restructuring principles that favor using competitive markets rather than ratepayer money to fund generation.[346] It also raises consumer protection issues, especially if a utility could rate base all the costs of the project.[347] Consequently, a state that wishes to pursue this solution should only let a utility include the value of an energy storage project's avoided T&D costs in its rate base. Doing so would properly require the utility to bear the risks of the project's wholesale market performance, and prevent it from using ratepayer money to undercut other market participants.[348]

B. Enable Shared Ownership or Control of Energy Storage Projects

Another way state policymakers could remove restructuring barriers to energy storage would be to allow utilities and third parties to share

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some of the benefits by lowering transactions and financing costs utility ownership offers. *See id.* (reporting empirical findings that introducing increased competition reduces the price of goods).

342. *See, e.g.*, N.H. REV. STAT. ANN. § 374-F:1 (2018) (establishing that competition in the electricity sector is an important legislative policy goal for New Hampshire).

343. *See, e.g.*, Stein, *supra* note 117, at 960 (noting that New York restricted utility ownership of distributed energy resources in part because of non-utility developers' opposition).

344. *See id.* at 958–60 (explaining that utility ownership of distributed energy resources simplifies the deployment process while also enabling lower financing and transaction costs).

345. LESSER & GIACCHINO, *supra* note 147, at 71–72.

346. Stein, *supra* note 117, at 960. Amy Stein also argues that "[w]hile there is some inherent appeal to the efficiencies associated with a reintegration of the ownership of [distributed] reliability resources with the utility, it is unclear if there is a principled end point to such a reintegration." *Id.* Thus, "[e]ven if valid justifications exist, regulators may be hesitant to carve out an exception for reliability resources for fear of a slippery slope." *Id.*

347. *See* LESSER & GIACCHINO, *supra* note 147, at 56 (overviewing the impact of cost shifting on ratepayers).

348. *See id.* at 71–72 ("When a regulated firm provides several products or services . . . it is important to ensure that the nonregulated costs are not tagged with the regulated costs. Doing so will not only unfairly increase the regulated prices the firm's customers pay, but it can nobble the firm's unregulated competitors . . . .").

ownership or control of an energy storage project.[349] In such a model, a distribution utility would receive the benefits of avoided T&D costs, while the third party would handle the energy storage project's participation in wholesale electricity markets.[350] This model prevents direct utility involvement in wholesale electricity markets, and preserves a role for competitive non-utility entities in energy storage.[351] Consequently, this model better comports with restructuring principles than a model in which utilities handle all aspects of an energy storage project.[352] However, it also increases project complexity, potentially increasing the costs of deploying energy storage.[353] While non-utility developers will likely prefer shared ownership, utilities will prefer a model over which they have sole control.[354]

1. Utility as Primary Owner

The Brattle Group has proposed one approach to shared ownership of energy storage.[355] In this model, utilities would deploy and own energy storage projects but *auction off* the right to wholesale market revenues to a third party.[356] The utility would use the income it receives from auctioning off such rights to reduce its customer's rates.[357] The third party would then handle bidding the project into wholesale markets and meeting the project's wholesale market obligations.[358] The third party would retain all wholesale market revenues to cover the costs of purchasing the project rights and make a profit.[359] In this model, the utility would not participate in wholesale markets, maintaining the restructuring policy of separating distribution and generation.[360] Likewise, the third party would bear all the risks of the

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349. *See* SKY STANFIELD, JOSEPH "SEPH" PETTA & SARA BALDWIN AUCK, CHARGING AHEAD: AN ENERGY STORAGE GUIDE FOR STATE POLICYMAKERS 30 (2017) (noting shared ownership's potential and outlining one form it could take).

350. *Id.*; CHANG ET AL., *supra* note 13, at 18.

351. CHANG ET AL., *supra* note 13, at 18.

352. *See supra* Part II.B (outlining that restructuring was meant to shield ratepayers from the costs of uneconomic generating assets as well as promote competition).

353. *See* Stein, *supra* note 117, at 958–60 (noting that utility ownership can avoid inefficiencies and high transaction costs).

354. *See id.* at 960 (noting that due to non-utility developers' opposition, New York restricted utility ownership of distributed energy resources).

355. CHANG ET AL., *supra* note 13, at 17–18.

356. *Id.* at 18.

357. *Id.*

358. *Id.*

359. *See id.* (implying that third parties would keep wholesale market revenue).

360. *Id.*

project underperforming in the wholesale market, rather than the utility's ratepayers.[361]

The Brattle Group's approach still requires changes to New England restructuring statutes.[362] After all, in this system, utilities still own energy storage projects that act as generators, even if someone else manages the project's wholesale market participation and retains the resulting revenue.[363] Moreover, by auctioning off the rights to the project's wholesale market revenue, a utility derives revenue from the project's generation functionality.[364] Utilities therefore financially benefit from their ownership of generation assets, which would violate New England's restructuring statutes.[365] Enabling such a system would therefore require legislative action. Statutory language to enable such system would look like this:

> Notwithstanding any provision of [citation to state's restructuring statute] . . . a utility may develop and own energy storage projects that reduce transmission or distribution costs . . . . A utility may contractually sell the right to bid such utility-owned energy storage projects into wholesale electricity markets to a non-utility. Any such contract shall provide that the non-utility shall retain any wholesale market revenue the energy storage project earns, and bear all risk of project underperformance in the wholesale market . . . . The utility shall use all compensation a

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361. *See id.* ("Under the envisioned policy framework, the TDSPs will continue to be only transmission and distribution service providers with no wholesale market participation."). However, the utility's ratepayers might still bear the risk of the auction not raising sufficient money to cover project costs a utility does not recoup through T&D cost savings. *See id.* at 17–18 (acknowledging this risk implicitly by proposing a safety margin requirement by which expected benefits would need to exceed expected costs).

362. *See 2015 Texas Legislature and Electric Power Policy: A Recap*, HUSCH BLACKWELL (July 2, 2015), https://www.huschblackwell.com/newsandinsights/2015-texas-legislature-and-electric-power-policy-a-recap (noting that the Texas legislature would have to enact statutory changes before a utility could implement the Brattle Group proposal).

363. *See* CHANG ET AL., *supra* note 13, at 17–18 (describing a model in which utilities would invest in and presumably own the energy storage project, but "auction off" the rights to bid it into wholesale markets).

364. *See id.* at 18 (noting that utilities would "'auction off' the wholesale market value of distributed storage").

365. *See supra* Part III.A (discussing how New England restructuring statutes restrict utility owned energy storage projects from earning revenue in wholesale electricity markets). However, the current version of Connecticut's restructuring statute would permit this arrangement, provided a utility made a competitive proposal to share ownership of an energy storage project called for in the State's Integrated Resource Plan. *See supra* Part III.A.5 (discussing the conditions under which a utility may own generation assets in Connecticut).

> non-utility pays the utility for the contractual right . . . to reduce retail electricity rates.[366]

2. Third Party as Primary Owner

Another shared-ownership approach has the third party as the primary owner of the energy storage project, with the third party providing T&D benefits as a service to the utility.[367] A state could treat the third party as selling the project's T&D attributes to the utility.[368] However, the third party would need to know where to deploy a project to maximize T&D benefits.[369] As utilities likely possess more of this information than anyone else,[370] this model requires some mechanism to induce utilities to tell third parties where optimal deployment sites are.[371]

State policymakers could require utilities to locate such sites, and determine what T&D costs an energy storage project located there might avoid.[372] A state could then require or allow its utility commission, or the utilities themselves, to solicit competitive proposals to construct energy storage projects in prime locations.[373] Such a competitive process could specify the maximum payments the utility can likely provide to third parties, based on the utility's avoided-cost estimates.[374] The utility or the commission could select the project proposal that provides the greatest net

366. H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(III) (N.H. 2019).

367. *See, e.g.*, *id.* sec. 2, § 374-H:3(II)(b)–(c) (proposing a system to enable such an approach legislatively).

368. *Cf. id.* sec. 2, § 374-H:3(II)(b) ("[T]he rules shall require a utility to compensate a non-utility for the value of all transmission and distribution costs the utility will likely avoid because of the [non-utility] energy storage project.").

369. *Cf.* Lueken et al., *supra* note 20, at 11 (arguing that states should find ways to integrate energy storage into T&D processes and address the lack of accepted ways to compensate the T&D value of energy storage projects).

370. *See* Peskoe, *supra* note 306, at 294 (noting that utilities know more about their own costs than anyone else).

371. *See, e.g.*, H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(II) (N.H. 2019) (proposing to legislatively mandate a certain amount of non-utility-owned energy storage); *id.* § 374-H:3(II)(a) (proposing to order the Commission to prioritize non-utility-owned energy storage projects that avoid T&D costs); *id.* § 374-H:3(I) (proposing to order the Commission to use its rule-making authority to create programs that implement these provisions).

372. *Cf. id.* § 374-H:3(I), (II)(a) (proposing to order the Commission to to create programs that facilitate developing non-utility-owned energy storage projects that avoid T&D costs).

373. *See id.* § 374-H:3(I), (II)(a) (proposing to order the Commission to create programs that facilitate deploying non-utility-owned energy storage projects that avoid T&D costs, thereby granting it authority to create such a competitive solicitation program).

374. *See id.* § 374-H:3(I), (II)(a) (proposing to order the Commission to create programs that implement these provisions, thereby granting it authority to create such a competitive solicitation program).

T&D cost savings.[375] Such a design ensures that the utility—and ultimately its ratepayers—will not overpay for the project. Inasmuch as the third-party owner secures financing to build the project and handles the project's wholesale market participation, it would bear the project development and market risks.[376] This would shield ratepayers from all risks associated with the project's generation side.[377] It also keeps the utility's role in the project completely separate from the project's generation side, in accordance with restructuring principles.[378]

The potential problem with this model is the financial implications for the utility. Distribution utilities only make a return on their rate base, which is traditionally just their own physical infrastructure, equipment, and working capital.[379] They recover—but make no profit on—any other costs, such as contract payments to a third party.[380] A utility would forego *all* of the profit it would have made by building traditional distribution infrastructure if it instead contracted third-party-owned energy storage to perform the distribution function. In principle, policymakers could still require a utility to contract for third-party-owned storage.[381] However, trying to force utilities to do something directly against their financial interests poses practical problems.

First, utilities would obviously dislike such a system and probably oppose any effort to create it.[382] Generally, earning a rate of return on rate-based investments is the only way a utility profits from providing distribution service.[383] Requiring a utility to forego such profit whenever energy storage is the cheapest solution may create a major threat to their core business model.[384] As such, utilities would likely try to derail such a

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375. *Cf. id.* § 374-H:3(II)(a) ("The commission's regulations shall create a preference for non-utility energy storage projects that avoid or reduce transmission and distribution costs.").

376. *See id.* § 374-H:3(VI) (emphasizing that utilities would not have any role regarding the wholesale market side of the project under the proposed system).

377. *See id.* (implying such a shield by noting utilities would not participate in the wholesale markets, and thus would not expose themselves to generation risks they could pass on to ratepayers).

378. *See id.* ("Nothing in this section shall give a utility the right to . . . directly participate in wholesale electricity markets."); N.H. REV. STAT. ANN. § 374-F:3(III) (2018) ("Generation services should be . . . at least functionally separated from transmission and distribution services . . . .").

379. LESSER & GIACCHINO, *supra* note 147, at 63–64.

380. *Id.* at 48, 63.

381. *See, e.g.*, H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(II) (N.H. 2019) (proposing to legislatively mandate non-utility-owned energy storage).

382. *See supra* Part I.A.2 (explaining how investor-owned utilities prefer models that grant returns to their investors).

383. LESSER & GIACCHINO, *supra* note 147, at 63.

384. *See id.* at 63–64 (explaining that utilities make their profits by placing physical infrastructure in their rate base).

system before it ever came into existence.[385] Establishing such a system would be politically costly for state policymakers, and may well be politically infeasible.[386]

Second, even if a state were to implement such a system, utilities would have the means, motive, and opportunity to undercut it. After all, such a system would depend on the utilities themselves providing information—which probably only they possess—about the extent of the costs an energy storage project would avoid.[387] Moreover, utilities can "exploit [such] an obvious information asymmetry" and "mold a cost-of-service study to meet [their] own goals, such as [creating entry barriers] for alternative service providers."[388] In other words, utilities can strategically misrepresent the details about their cost structures, and thus undervalue potential third-party energy storage projects.[389] Granted, the regulatory oversight of utility commissions may check this practice somewhat. However, commissions have limited resources, and thus may not detect every misrepresentation.[390] Consequently, state policymakers should expect that under such a system, this *strategic* utility behavior will lead to inefficiently low levels of energy storage deployment.[391]

However, a simple solution to this problem exists—allow utilities to include the value of such contract payments to third-party owners in their rate base.[392] This would allow the utilities to earn a profit on such

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385. *Cf.* Peskoe, *supra* note 306, at 260–75 (discussing how many investor-owned utilities have sought to undermine distributed energy resources, particularly rooftop solar, because they perceived them as a threat to their business).

386. *Cf. id.* at 260 (quoting KARL BOYD BROOKS, PUBLIC POWER, PRIVATE DAMS: THE HELLS CANYON DAM CONTROVERSY 131 (2009)) (noting that, with regard to distributed energy resources, utilities have employed tactics that "are reminiscent of campaigns launched in the twentieth century against government-backed utilities, which were smeared with 'the most lurid McCarthyite fantasies of the early 1950s'").

387. *See id.* at 294 (acknowledging that utilities have the most knowledge regarding their costs).

388. *Id.*

389. *See* Shelley Welton, *Public Energy*, 92 N.Y.U. L. REV. 267, 317 (2017) ("[I]nformation asymmetries allow utilities to exploit commissions in rate cases and earn rates of return higher than necessary to cover costs.").

390. *See* LAZAR & REGULATORY ASSISTANCE PROJECT STAFF, *supra* note 21, at 87 ("Although commissions do review . . . expenses to determine if they are reasonable before approving them, they may not have the staff adequate for them to really examine them in detail . . . .").

391. *Cf.* Peskoe, *supra* note 306, at 294 ("An IOU can mold a cost-of-service study to meet its own goals . . . ."); *id.* at 247 (noting that in the past utilities have "resorted to vindictive and mendacious tactics" to oppose threats to their business model).

392. *See, e.g.*, H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(II)(b) (N.H. 2019) ("If the non-utility energy storage project avoids the need for a new distribution or transmission project the utility could have added to its rate base, the commission may allow the utility to include . . . the value of the corresponding portion of its payment to the non-utility in its rate base.").

contracts.[393] As such, utilities would likely evaluate energy storage projects on more of an equal basis with traditional distribution infrastructure, rather than trying to block a storage solution. Moreover, insofar as energy storage projects act as distribution infrastructure, it is arguably reasonable to allow utilities to make a profit on them as with any other distribution infrastructure.[394]

A positive feature of this model is that, unlike the Brattle Group model, utility commissions have the authority to implement such a system themselves.[395] They possess the authority to allow utilities to rate base such contracts as part of their discretionary ratemaking authority.[396] The standard cost-of-service methodology is not a statutory requirement; state commissions possess "the authority . . . to devise unique systems for setting rates."[397] Consequently, state commissions can change aspects of their rate-setting methodology, provided that the resulting rate is just and reasonable.[398]

That in turn means a commission can change how it calculates a utility's rate base and revenue requirement, so long as the new method fairly compensates utilities and does not produce excessive rates for consumers.[399] Granting utilities a new ability to rate base contracts with a third-party energy storage project owner would not harm its financial interests.[400] Thus, such a change would continue to fairly compensate utilities.[401] Likewise, a contract that provides net savings to ratepayers relative to traditional distribution investments would reduce rates.

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393. *See* LESSER & GIACCHINO, *supra note* 147, at 63–64 (overviewing how utilities make their profits on physical infrastructure).

394. *Cf.* H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(II)(b) (N.H. 2019) (authorizing the Commission to allow such rate basing if the Commission finds it is "just" and "reasonable").

395. Of course, a state legislature could statutorily require a commission to implement such a system if the latter does not do so on its own initiative. *See, e.g.*, *id.* ("If the non-utility energy storage project avoids the need for a new distribution or transmission project the utility could have added to its rate base, the commission may allow the utility to include . . . the value of the corresponding portion of its payment to the non-utility in its rate base.").

396. *See* Scott, *supra* note 144, at 381 (noting that state commissions possess the legal authority "to devise unique systems for setting rates").

397. *Id.* at 381; *see also* HEMPLING, *supra* note 120, at 230 (explaining that "statutory-constitutional deference" gives commissions discretionary authority to choose different ratemaking methodologies).

398. HEMPLING, *supra* note 120, at 230. Remember that a rate is just and reasonable if it falls within a "zone of reasonableness" that fairly balances the financial interests of a utility and its ratepayers. *Id.* at 220–21.

399. *Id.* at 220–21.

400. *See* LESSER & GIACCHINO, *supra note* 147, at 63–64 (explaining that the an addition to the rate base would increase a utility's profits).

401. *Id.* at 63–64.

Therefore, allowing utilities to rate base contracts would still produce just and reasonable rates.[402]

Commissions can also require utilities to determine optimal sites for energy storage projects, the costs such projects might avoid, and to solicit third-party energy storage projects through a competitive process.[403] Utility commissions possess "broad authority to regulate utilities" in order to "keep[] rates as low as possible" for customers—provided utilities can still earn fair compensation for providing service.[404] For example, the Massachusetts Supreme Judicial Court held that the State's Department of Public Utilities "has the authority as a rate regulator to . . . require that [a] utility pursue a course likely to be less costly to ratepayers in the long term."[405] Utility commissions also have the authority to require that utilities determine when and where third-party owned energy storage projects are the most cost effective means of providing distribution service to ratepayers.[406] On the same basis, utility commissions could also require utilities to solicit projects through a competitive process, and contract for their T&D benefits when doing so would save ratepayers money.

Finally, allowing utilities to contractually procure T&D benefits from third-party energy storage owners would not violate New England restructuring statutes.[407] Unlike in the Brattle Group model, in this system a utility would never own the energy storage project itself. The third party would remain the main owner of the system. Depending on how a utility commission chose to treat the arrangement, the utility would either buy a service or acquire ownership of just the T&D attributes of an energy storage project. Either way, the utility would not own the project's generation attributes or any rights to them; the utility would not participate or derive

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402. *See* Appeal of Pub. Serv. Co. of N.H., 547 A.2d 269, 271 (N.H. 1988) ("In setting rates, a regulatory commission follows a process of identifying consumer and producer interests competing for recognition, with an ultimate goal of striking a fair balance . . . that may be described as just and reasonable both to the customer and to the utility.").

403. *See, e.g.*, N.H. REV. STAT. ANN. § 374:3 (2018) (granting the New Hampshire Public Utilities Commission the broad power to supervise utilities).

404. Scott, *supra* note 144, at 392. Furthermore, "most states' utility codes include general authority clauses, extending the authority of the commissions to all acts necessary to carry out their statutory authority." *Id.* at 383–84. For example, New Hampshire statutory law provides that "[t]he public utilities commission shall have the general supervision of all public utilities and the plants owned, operated or controlled by the same so far as necessary to carry into effect the provisions of this title." N.H. REV. STAT. ANN. § 374:3 (2018).

405. Mass. Elec. Co. v. Dep't of Pub. Util., 643 N.E.2d 1029, 1034 (Mass. 1994).

406. *See* Scott, *supra* note 144, at 392 (stating that utility commissions possess "broad authority to regulate utilities" in order to "keep[] rates as low as possible" for customers).

407. However, in the case of New Hampshire, its separate statute restricting utility investment in distributed energy resources—including energy storage—would still apply. *See supra* Part III.A.6 (discussing the conditions under which a utility can own distributed generation in New Hampshire).

any revenue from the project's generation side. Unlike the Brattle Group model or sole utility ownership, a utility commission could implement this model of shared ownership even in the absence of any statutory change.

Both shared ownership models possess several other advantages over the sole utility ownership model. They better adhere to the spirit of restructuring principles by keeping utilities uninvolved in the generation side of an energy storage project.[408] They also preserve a competitive role for third parties in the energy storage space.[409] Such competition would also exert market pressure on energy storage projects, potentially helping to control their costs.[410] Competitive non-utility businesses interested in developing and operating energy storage projects are also likely to support rather than oppose such a system.[411] Maintaining utilities' ability to rate base the distribution or transmission value of such projects would, at the very least, blunt utility opposition to such a system.[412] Consequently, shared ownership models may offer a more politically workable compromise between restructuring proponents, utilities, and third parties than a sole-utility-ownership model.

Shared ownership does sacrifice the cost savings a utility might capture by not involving a third party and financing the project itself.[413] As noted above, monopoly utilities can borrow money at lower rates than competitive businesses.[414] Likewise, not involving a third party reduces the transaction costs of developing the energy storage project.[415] Consequently, a shared-ownership model would likely involve greater transaction and financing costs than sole utility ownership.[416] If these cost increases outweigh the downward cost pressure of market competition, shared

408. *See* H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(VI) (N.H. 2019) ("Nothing in this section shall give a utility the right to . . . directly participate in wholesale electricity markets."); N.H. REV. STAT. ANN. § 374-F:3(III) ("Generation services should be . . . at least functionally separated from transmission and distribution services . . . .").

409. CHANG ET AL., *supra* note 13, at 18.

410. *See* Busso & Galiani, *supra* note 341 ("[T]he entry of new competitors leads to price reductions by putting more competitive pressure on market incumbents.").

411. *See* Stein, *supra* note 117, at 960 (providing New York's rationale for restricted utility ownership of distributed energy resources).

412. *See* LESSER & GIACCHINO, *supra note* 147, at 63–64 (overviewing what goes towards calculating a utility's profits).

413. *See* Stein, *supra* note 117, at 958, 960 (noting that utility ownership can avoid inefficiencies and high transaction costs).

414. HIRSH, *supra* note 130, at 23–24.

415. *See* Stein, *supra* note 117, at 958, 960 (addressing methods to avoid inefficiencies and high transaction costs).

416. *See id.* (implying that economies of scale and ensured returns exist help utilities avoid inefficiencies and high transaction costs).

ownership could increase project costs and lead to lower levels of energy storage deployment.

In short, shared ownership may be more politically feasible,[417] enable more competition in energy storage deployment,[418] and better adhere to restructuring principles than sole-utility ownership.[419] In addition, commissions could implement one version of shared ownership even in the absence of statutory change.[420] The trade-off, however, is higher financing and transaction costs for energy storage projects,[421] though downward pressure on costs from greater market competition might offset these increases.[422] Nonetheless, shared ownership may still entail higher costs and thus lead to less energy storage deployment than sole utility ownership.

C. The Best Path Forward

Whether sole-utility or shared ownership is preferable will depend upon a state's policy priorities. If simply maximizing energy storage deployment is the only goal, sole-utility ownership is likely the best option.[423] Conversely, shared ownership provides the best option to policymakers who wish to privilege restructuring and competition.[424] Shared ownership also has the advantage of not requiring statutory change, unlike a sole-utility-ownership model.[425] Policy experiments with the different models would allow policymakers to evaluate the relative merits

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417. *See id.* at 960 (overviewing opposition to utility ownership of distributed energy resources).

418. *See supra* Part IV.B (explaining why shared ownership leads to more competition).

419. *See* H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:3(VI) (N.H. 2019) (emphasizing that under the proposed shared-ownership framework, utilities would not be involved in the generation side of energy storage projects); N.H. REV. STAT. ANN. § 374-F:3(III) (2018) ("Generation services should be . . . at least functionally separated from transmission and distribution services . . . .").

420. *See supra* notes 396–408 and accompanying text (asserting why commissions have the ability and authority to implement one version of the shared-ownership model on their own).

421. *See* Stein, *supra* note 117, at 958, 960 (noting that non-utility ownership can be less efficient than utility ownership).

422. *See* Busso & Galiani, *supra* note 341 ("[T]he entry of new competitors leads to price reductions by putting more competitive pressure on market incumbents.").

423. *See* Stein, *supra* note 117, at 958–960 (explaining that utility ownership of distributed energy resources simplifies the deployment process while also enabling lower financing and transaction costs).

424. *See supra* Part IV.B (arguing how shared ownership better comports with restructuring principles and enables greater competition).

425. *See supra* Part IV.A (noting that enabling sole-utility ownership would require statutory change); *see supra* Part IV.B (clarifying that enabling shared ownership would not require statutory change). New Hampshire is a partial exception, as it allows utilities to own generation assets under some restrictive conditions. *See supra* Part III.A.6 (discussing the conditions under which a utility can own generation assets in New Hampshire).

of each model under real-world conditions.[426] This will provide policymakers with the information needed to balance competing policy priorities and determine best practices.[427]

In order to achieve optimal levels of energy storage deployment in the shortest possible timeframe, this Note proposes that states pass legislation authorizing the adoption of several different models. Such legislation should allow sole-utility ownership of energy storage, with a legal cap on market share to prevent crowding out non-utility competitors. For example, the legislation could limit utility-owned energy storage to no more than 50% of deployed energy storage projects.[428] All remaining energy storage projects would be shared ownership projects or projects that do not involve utilities. The legislation would permit utilities to rate base only the value of avoided T&D costs and the reliability benefits of their energy storage projects.[429] Utilities or third parties, rather than ratepayers, would thus shoulder the risk of project underperformance in wholesale electricity markets.[430]

Such a policy design has three main advantages. First, on passage it immediately enables deployment of energy storage free of restructuring restrictions. Second, it allows policymakers to gather real-world data on the practicality of each model. In particular, it would provide data about the relative costs of developing utility-owned and shared-ownership energy storage projects that would give policymakers data on the size of any cost premium shared-ownership requires. From that, policymakers could reasonably estimate what effect barring sole-utility ownership might have on energy storage deployment levels. Third, this policy design avoids prematurely locking a state into either a sole-utility-ownership or shared-ownership model.

426. *Cf.* H.B. 715-FN, 2019 Gen. Court, Reg. Sess., sec. 2, § 374-H:2(II) (N.H. 2019) (directing the New Hampshire Public Utilities Commission to study the benefits of energy storage after a storage deployment program using different ownership models has begun).

427. *Cf. id.* § 374-H:2(IV) (directing the Commission to use such information in setting a higher energy storage target).

428. *See, e.g.*, *id.* § 374-H:3(II) (proposing to require that non-utilities own at least 50% of energy storage projects). Note, however, that H.B. 715 only enables the two shared-ownership models—utility as primary owner and third party as primary owner—because it expressly maintains the restructuring restrictions on utility participation in wholesale electricity markets. *See id.* § 374-H:3(VI) ("Nothing in this section shall give a utility the right to . . . directly participate in wholesale electricity markets.").

429. *See supra* Part IV.A (identifying why utilities should not be allowed to rate base the entire cost of an energy storage project).

430. *See supra* Part IV.A (describing how this allocation of risk protects ratepayers).

In practice, however, the best policy is whatever is most politically feasible in a given state.[431] Recall that removing restructuring barriers to energy storage could potentially increase energy storage deployment fivefold to sevenfold.[432] That extra energy storage deployment could significantly reduce air pollution in New England,[433] while saving ratepayers billions of dollars.[434] The relative differences in the benefits, costs, and deployment levels of sole-utility and shared ownership likely pale in comparison. In other words, the marginal benefit of picking the better way to remove restructuring barriers is small compared to the benefits of simply removing the barriers.

As such, policymakers should not make the perfect the enemy of the good. They should only seek to optimize the policy design to the extent that doing so does not decrease the chances of actually implementing the policy. Policymakers' primary goal should be simply to remove the barriers.

CONCLUSION

Energy storage can reduce the cost of electricity while playing a key role in the fight against climate change. However, policymakers did not design the current electricity regulatory system with its unique characteristics in mind. This problem is particularly acute in New England's restructured markets. By maintaining monopoly distribution utilities while restricting a utility's ability to own generation, such states have inadvertently restricted the range of benefits energy storage can offer the grid. New England might needlessly overpay billions for its electricity and undermine the fight against climate change if no legal changes occur to remove these barriers.

This Note offers multiple ways policymakers could address the barriers preventing optimal utilization of energy storage in New England. Both exempting energy storage from utility-ownership restrictions or enabling shared ownership of energy storage provide potential solutions. As each solution has its own advantages and drawbacks, states should initially enable both to flourish under a time-limited market share cap. Doing so

431. *See, e.g.*, H.B. 715-FN (proposing to allow shared-ownership but not sole-utility ownership to comport with state restructuring principles).

432. CHANG ET AL., *supra* note 13, at 8; LUEKEN ET AL., *supra* note 20, at 19. Note, however, that the sevenfold increase may depend on removing other state level barriers as well. *See* LUEKEN ET AL., *supra* note 20, at 11 (indicating that states may need to provide stable rate design and further clarify regulatory treatment of energy storage, particularly energy storage paired with renewables, to unlock its full potential).

433. *See supra* Part I.A (noting the environmental benefits of energy storage).

434. MASS. DEP'T OF ENERGY RES. ET AL., *supra* note 11, at 77, 88.

would allow policymakers to evaluate the real-world performance of both models without committing to either or stalling energy storage deployment in the interim. However, policymakers should implement some solution in the near future. The benefits of removing the barriers outweigh the potential inefficiencies of doing so in a less-than-perfect manner. Fortunately, in the world of policies that help address climate change, doing so should be relatively easy. Enabling more energy storage through regulatory changes offers a win-win-win for New Englander's pocketbooks, the environment, and future generations.

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