EXPERT REPORT

Opinion re "Expert Report of Mark Jacobson, Ph.D." April 6, 2018

Kelsey Cascadia Rose Juliana, et al. v. United States of America, et al.

Case No. 6:15-CV-01517-TC

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1. Introduction

This expert report is submitted in connection with the matter known as *Kelsey Cascadia Rose Juliana; Xiuhtezcatl Tonatiuh M., through his Guardian Tamara Roske-Martinez; et al., v. The United States of America; Donald Trump, in his official capacity as President of the United States; et al., United States District Court, District of Oregon Case No. 6:15-cv-015-17-TC*. I have been asked to assess claims made by Mark Z. Jacobson regarding "the feasibility of transitioning the United States of America to 100% clean and renewable energy in all energy sectors by mid-century," as proffered by Dr. Jacobson in his Expert Report (page 1), dated April 6, 2018. The opinions contained in this report are based on my professional knowledge, training, and experience. I reserve the right to supplement this report as additional information is made available.

2. Qualifications

I am a Senior Research Engineer[1] at the Massachusetts Institute of Technology (MIT) in the MIT Energy Initiative[2], an interdisciplinary laboratory that carries out energy-related research. I have worked as an energy researcher at MIT for over 29 years. My primary focus for the past 15 years has been carbon dioxide capture and storage (CCS). I also have worked extensively in the fields of geothermal energy, industrial energy efficiency, biomass, and energy conversion (e.g., biomass to transport fuels). Sponsors of my research have included industry, government, and environmental organizations. These sponsors have been both domestic and international. My curriculum vitae is included as Appendix A to this report, and a list of my publications from 2008 to the present is contained in Appendix B.

My research has focused on improving the environmental performance of energy systems in the United States, especially with respect to the de-carbonization of such systems. I received a Certificate from the Intergovernmental Panel on Climate Change (IPCC) for my work on the IPCC Special Report on Carbon Dioxide Capture and Storage. The certificate reads: "presented to Howard Herzog for contributing to the award of the Nobel Peace Prize for 2007 to the IPCC." I was the coordinating lead author on the chapter entitled "Costs and economic potential."[3]

I trained as a Chemical Engineer at MIT, and spent ten years in industry, before returning to MIT in 1989 to join the research staff. My work at MIT focuses on the interrelationship between technology and policy as it relates to energy systems and climate change. I have supervised the research of dozens of MIT graduate students, who have subsequently successfully defended their masters and doctorial theses. I founded and directed the Carbon Sequestration Initiative, an industrial consortium focused on CCS with 26 member companies. Currently, I chair the steering committee for the International Energy Agency's Greenhouse Gas R&D Programme's CCS Cost Network.

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[1] This is the highest position on the research staff at MIT.

[2] The founding director of the MIT Energy Initiative is Prof. Ernest Moniz, who served as U.S. Secretary of Energy from May 2013 to January 2017.

[3] Each chapter had two Coordinating Lead Authors (CLAs), with support from between 5 and 20 or more lead authors. CLAs participated in the drafting of the Summary for Policy Makers and the Technical Summary.

I have an extensive background in modeling. I have expertise in developing engineering cost models, including but not limited to detailed models for enhanced geothermal systems, CCS, and conversion of biomass to fuels. I am the co-founder of Aspen Technology, a firm that develops process simulation models[4]. At MIT, I work closely with the energy economists who developed the Emissions Prediction and Policy Analysis (EPPA) model, which is a multi-sector, multi-regional general equilibrium model of the world's economy. My supervision of MIT graduate students involves engagement with many types of computational models, including process models, dynamic models, electricity system dispatch models, costing models, and the EPPA model.

I have authored a book for The MIT Press Essential Knowledge Series entitled *Carbon Capture*. It will be released in September, 2018.

3. Summary Overview

The Plaintiffs in this case have put forward a proposal to convert 100% of the energy system of the United States of America to renewable energy by the year 2050. Specifically, the Expert Report of Mark Z. Jacobson, dated April 6, 2018, states:

> "I conclude … that it is both technically and economically feasible to transition from a predominantly fossil fuel-based energy system to a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030…" (page 2)

Jacobson refers to this framework as "100% WWS (wind, water, solar)." He further states

> "Our research further finds that the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost …)" (page 4)

Jacobson (Expert Report, page 4) affirms that "the methodology for this research" is "outlined in detail in Jacobson *et. al.* (2015a, 2015b) and updated in Jacobson *et al*. (2017a; 2018)". The four papers can by organized as shown below:

Paper Focus	Original Paper	Updates
100% WWS Roadmaps	Jacobson *et al.* (2015a)	Jacobson *et al.* (2017a)
Grid Integration & Reliability	Jacobson *et al.* (2015b)	Jacobson *et al.* (2018)

I examined and assessed the facts and data, along with the principles and methods applied by Jacobson to support his conclusions that: (1) "it is both technically and economically feasible to transition from a predominantly fossil fuel-based energy system to a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030…" (page 2); and (2) "the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost …" (page 4).

[4] Process simulation models assist engineers in the design and operation of industrial processes, such as oil refining, chemical production, power generation and many more.

It is my expert opinion that Jacobson's conclusions are based on insufficient facts and data, and the incorrect application of generally accepted methods. As a result, I believe that Jacobson's opinions cannot be reasonably relied upon. Specifically, Jacobson's conclusions are unreliable, because he: (1) relies on flawed data, (2) does not sufficiently analyze critical areas, and (3) applies a flawed methodology, making them unreliable in their application to support his conclusions. Below, I summarize the issues with Jacobson's data and methods. In the appendices of this report, I provide analyses to support my findings.

First, Jacobson fails to define what he means by "technically and economically feasible." In my expert opinion, concluding that an engineered system is technically feasible requires evidence that the technology has been demonstrated at scale, with its performance characteristics sufficiently well-documented, such that required permits and financing are obtainable. It also is my expert opinion that concluding that an engineered system is economically feasible from a project financing perspective requires evidence that the technology has similar or lower costs than competing technologies, and/or has benefits, for which the facts evidence that people are willing to pay additional costs. Jacobson fails to offer such evidence in his expert report.

Second, it is my expert opinion that Jacobson's proposed timelines for building, installing, and deploying the necessary facilities and infrastructure to transition to his proposed energy system are unrealistic and likely infeasible by failing to address myriad real-world considerations. He provides insufficient data and offers no reliable methodology to support his proposed timelines (Section 4.1).

Third, it is generally accepted that three criteria are necessary to demonstrate, in Jacobson's own words, a "solution to the grid reliability problem" (Jacobson et al. 2015b, page 15060). Jacobson fails to demonstrate that his 100% WWS system satisfies these criteria, specifically:

1. **Supply and demand must match at all times**. It is my expert opinion that the simulations run by Jacobson using the LOADMATCH model are not consequential, because they include unrealistic assumptions regarding energy storage, hydrogen production, demand response, and hydroelectric power. The data and facts underlying his model are flawed and insufficient, which prevents the reliable application of his methodology (Section 4.2).

2. **Electricity must be moved effectively from where it is generated to where it is used**. Jacobson's simulations assume that new long-distance transmission lines will solve this problem. It is my expert opinion that his solution is insufficiently supported by data and contains no modeling or simulation to demonstrate that the proposed long-distance transmission framework will work. Further, Jacobson presents insufficient facts or data regarding key implementation issues for long-distance transmission, such as siting, permitting, and governance (Section 4.3).

3. **Grid services, such as frequency control, operational reserves, and security are essential to a properly-functioning energy system**. Jacobson's modeling and simulations pay little or no attention to these concerns. It is my expert opinion that Jacobson offers insufficient data and does not apply reliable principles and methods to show how his proposal will satisfy these essential services (Section 4.4).

Fourth, it is my expert opinion that Jacobson's work failed to reliably apply principles and techniques of cost estimation. Specifically, Jacobson's Expert Report, and his supporting analyses in Jacobson et al. (2015b) and Jacobson et al. (2018), fail to conform to best practices in cost estimation, including modeling the cost of capital, estimating total capital costs, determining capacity factors, indexing year dollars, and accounting for macroeconomic impacts (Section 4.5).

In summary, it is my expert opinion that, because Jacobson: (1) uses insufficient and/or flawed facts or data, (2) does not use reliable methods for key aspects of his proposed solution, and (3) does not apply generally accepted principles and techniques reliably to support key components of his testimony, he fails to evince that it is both technically and economically feasible to transition from a predominantly fossil fuel-based energy system to a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030. Furthermore, these flaws render his claim that costs of a 100% WWS energy system will be "similar or less than today's direct energy cost" (Jacobson Expert Report, page 4) invalid. Finally, I believe that the timeline proposed by Jacobson to transform the United States energy system to 100% WWS is unsubstantiated and unrealistic.

The sections that follow discuss my assessment of Jacobson's Expert Report. Jacobson fails to provide all of the inputs and outputs underpinning his models, and therefore my assessment is limited to the information included in his Expert Report, and that which is publically available. I reserve the right to revisit my assessment and update this report should additional material be made available to me.

I note that I am not the only scholar to have concerns with the data, methods, and findings posited by Jacobson. Scholars, including those who have performed peer review on Jacobson's publications, have reached conclusions similar to my own. Specifically Clack et al. (2017)[5] and Heard et al. (2017) noted the following about Jacobson et al. (2015b), which Jacobson asserts is the foundation of his Expert Report:

> "The scenarios of [Jacobson et al. 2015b] can, at best, be described as a poorly executed exploration of an interesting hypothesis. The study's numerous shortcomings and errors render it unreliable as a guide about the likely cost, technical reliability, or feasibility of a 100% wind, solar, and hydroelectric power system. It is one thing to explore the potential use of technologies in a clearly caveated hypothetical analysis; it is quite another to claim that a model using these technologies at an unprecedented scale conclusively shows the feasibility and reliability of the modeled energy system implemented by midcentury." (Clack et al., 2017, page 6727)

> "If one reaches a new conclusion by not addressing factors considered by others, making a large set of unsupported assumptions, using simpler models that do not consider important features, and then performing an analysis that contains critical mistakes, the anomalous conclusion cannot be heralded as a new discovery. The

[5] Clack et al. (2017) is a direct rebuttal to Jacobson et al (2015b). Clack had 20 energy experts as co-authors, including two from Jacobson's employer, Stanford University. Clack et al. identified insufficient power system modeling, including 2 modeling errors, 9 implausible assumptions, and 3 instances of inadequate scrutiny of the climate model that Jacobson employed.

> conclusions reached by [Jacobson et al., 2015b] about the performance and cost of a system of "100% penetration of intermittent wind, water and solar for all purposes" are not supported by adequate and realistic analysis and do not provide a reliable guide to whether and what cost such a transition might be achieved." (Clack et al., 2017, page 6727)

> "For example, some studies have done system simulations… but have made unrealistic assumptions in setting up the simulation… The work of [Jacobson et al., 2015b] is an example of this because it depends strongly on extraordinary assumptions relating to electrification, energy storage and flexibility in demand. Although this work scored [the highest grade] for a fine-grained timescale simulation, the results of such a simulation are likely to be meaningless because the underlying assumptions are unrealistic." (Heard et al., 2017, page 1130)

4. Review and Assessment of Jacobson's Expert Report

4.1 Finding #1: Jacobson's proposed timelines for building, installing, and deploying the necessary facilities and infrastructure to transition the United States energy infrastructure to his proposed energy system are unrealistic and probably infeasible.

Jacobson's Expert Report page 16 contains a section, titled "Timelines for Transitioning Individual Sectors," wherein he provides a list of proposed transformation timelines for each sector. Jacobson's overall stated goal is "80% [WWS] by 2030 and 100% [WWS] by 2050," but he does not provide any details or roadmaps for achieving these goals.

Specifically, Jacobson's proposed energy system would require large-scale development of new energy infrastructure, including solar and wind farms in addition to transmission, distribution, and storage infrastructure. Nowhere in his Expert Report does Jacobson address siting, design, permitting, or financing for the necessary facilities and infrastructure. In my view, given the timing required for these considerations, and for construction itself, it is improbable that sufficient solar and wind capacity can be constructed to meet U.S. energy demand within the timeline proposed by Jacobson in his Expert Report.

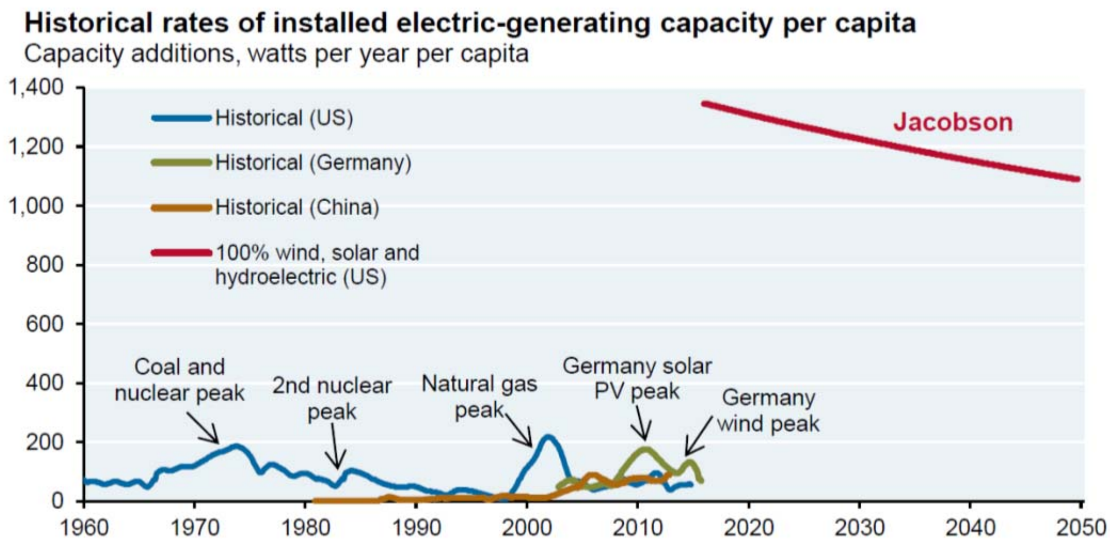
Further, Jacobson fails to comment on the numerous coordination issues associated with rapid, large-scale transformation of the U.S. energy system. Notably, Jacobson proposes simultaneous transformation of all three aspects of the energy system – energy supply (power plants), energy demand (including commercial, residential, transportation, etc.), and the grid (an interconnected national grid, with heavy reliance on storage). The practical challenges associated with simultaneous transformation of this sort, each of which relies on the other to progress, are substantial.

It is unclear from Jacobson's Expert Report, or the sources he cites, exactly *how* this large-scale energy system transformation will take place. With only proposed timelines and no detailed blueprint, it is not self-evident how the myriad coordination issues inherent to any such transformation will be mitigated.

Figure 1 below supports my contention that the build-out necessary to meet Jacobson's proposed transition to 100% WWS by 2050 is an order of magnitude greater on a per capita basis than recent build-outs undertaken by the U.S., Germany, and China.

In my expert opinion, the timelines posited by Jacobson to build, install, and deploy the necessary facilities and infrastructure to transition the United States energy infrastructure to a proposed 100% WWS energy system are unrealistic and, in my opinion, infeasible.

Figure 1



Source: Michael Cembalest, Eye on the Market: Annual Energy Paper April 2018, p. 20, available online at: https://www.jpmorgan.com/jpmpdf/1320745241034.pdf.

4.2 Finding #2: Jacobson fails to demonstrate that his proposed energy system can match electricity supply and demand at all times, a requirement of technical feasibility.

Wind and solar power are intermittent. Wind turbines only produce electricity when there is wind; solar panels only produce electricity when the sun shines. Because wind and solar produce less than 10% of our current electricity[6], dealing with the intermittency of wind and solar power is not a significant challenge for our energy system. If the wind stops and the sun doesn't shine, electricity generated by natural gas, coal, or nuclear plants can be dispatched to meet electricity demand.

In my view, if the energy system relies on wind and solar for over 95% of total electricity generation, as proposed by Jacobson's Expert Report, the system will not be able to match

[6] U.S. Energy Information Administration, U.S. Department of Energy, "What is U.S. electricity generation by source?", 2017 preliminary data, lasted updated March 7, 2018. Available online at: https://www.eia.gov/tools/faqs/faq.php?id=427&t=3, accessed August 3, 2018. These data indicate that utility-scale electricity generation was 6.3% wind and 1.3% solar, while natural gas, coal, and nuclear constituted 32%, 30%, and 20% of electricity generation, respectively.

electricity supply and demand at all times.[7] Due to intermittency, there will be times when energy supply greatly exceeds energy demand. There will be other times when energy supply will be insufficient to meet demand. This variability is a significant problem. A requirement of technical feasibility is that electricity systems must balance supply and demand at all times.

Jacobson et al. (2015b) documents how their "LOADMATCH" model matches electricity supply and demand at all times by relying on three primary strategies: 1) energy storage; 2) demand response; and 3) dispatching of hydroelectric power.

Based on my review, detailed in the subsequent sections of this report, I believe that Jacobson et al. rely on unrealistic assumptions in their model, and therefore the results of their simulations are not consequential. Specifically, my analysis indicates that Jacobson's underlying assumptions about energy storage, demand response, and the dispatching of hydroelectric power, the three primary strategies that his LOADMATCH model uses to match electricity supply and demand at all times, are not simply unrealistic, but also unsubstantiated. This model also was reviewed by Heard et al. (2017); their assessment of the model as follows: "Although this work scored [the highest mark] for a fine-grained timescale simulation, the results of such a simulation are likely to be meaningless because the underlying assumptions are unrealistic" (Heard et al., 2017, page 1130).

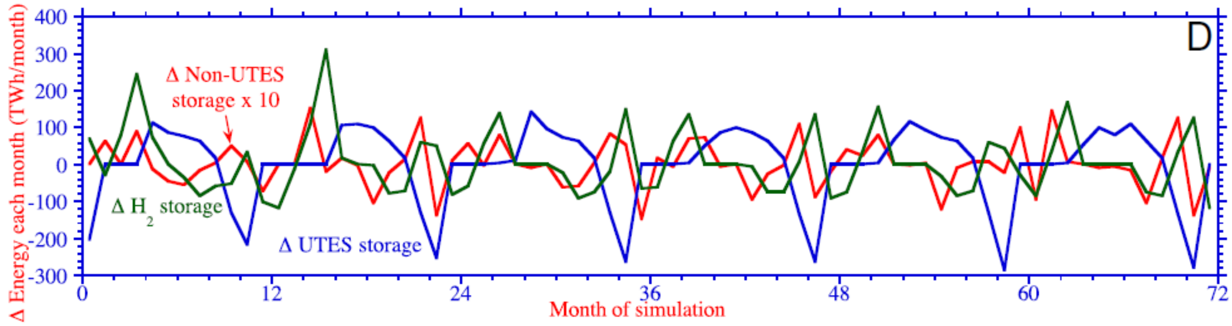
It is my expert opinion that Jacobson's LOADMATCH model and the estimates, findings, and conclusions in his Expert Report, which are derived from and based upon his LOADMATCH model, fail to adequately demonstrate that his proposed energy system is both technically feasible and capable of matching electricity supply and demand at all times.

4.2.1 Assessment of Jacobson's Modeling of Energy Storage

Jacobson et al. (2015b) documents that LOADMATCH uses several energy storage technologies to align electricity demand with electricity supply. As shown in Figure 2, (reproduced from Jacobson et al., 2015b (page 15062), Jacobson et al. (2015b) rely primarily on hydrogen storage and underground thermal energy storage (UTES) as their storage mechanisms to ensure sufficient supplies of electricity exist to meet demand for electricity at all times. Therefore, I focus my assessment on these two technologies. I summarize my analysis of these systems below, with additional detail provided in Appendices C and D for hydrogen storage and UTES, respectively.

[7] The Executive Summary of Jacobson's Expert Report states: "Second, averaged over the United States, our roadmaps propose that all-purpose U.S. energy in 2050 could be met with ~30.9% onshore wind, ~19.1% offshore wind, ~30.7% utility-scale photovoltaics (PV), ~7.2% rooftop PV, ~7.3% concentrated solar power (CSP) with storage, ~1.25% geothermal power, ~0.37% wave power, ~0.14% tidal power, and ~3.01% hydroelectric power (where virtually all hydroelectric dams exist already)" (pages 2-3). Only the latter four categories, summing to 4.77%, reflect non-wind, non-solar sources of electricity generation.

Figure 2. Six-year time series comparison of energy storage changes used to align electricity demand with electricity supply per Jacobson et al. (2015b)



Source: Jacobson et al., (2015b), Figure 2, Panel (D), page 15062.

4.2.1.a. Assessment of Jacobson's Modeling of Hydrogen Storage

There are two essential flaws with hydrogen storage as proposed and modeled in Jacobson et al. (2015b) and Jacobson et al. (2018).[8]

1) Jacobson severely underestimates the cost to operate the proposed hydrogen storage system; and

2) Jacobson does not address the costs and barriers associated with transforming the transportation and industrial sectors to hydrogen use.

My analysis indicates that Jacobson underestimates costs for the hydrogen storage system by at least a factor of ten, as I detail in Appendix C. In my view, there are three main reasons for his underestimation:

- **The capacity factors[9] used by Jacobson in his analysis are overestimated by a factor of approximately eight, which yields an underestimation in hydrogen storage system costs by a factor of over five.** Jacobson cites to Jacobson et al. (2015b), which cites to Jacobson et al. (2005), as his source for the cost of hydrogen production. Within the 2005 paper, Jacobson calculates hydrogen production costs using a range of capacity factors from 50% to 95%. However, Jacobson uses these hydrogen production costs in Jacobson et al. (2015b), which definitively shows that the capacity factor for the hydrogen storage system can be no greater than 9% (see Appendix C, Issue #3). The lower the capacity factor, the greater the cost per kilogram of hydrogen produced.[10] I believe that Jacobson failed to return to his earlier (2005) work to readjust the hydrogen storage system costs to account for the appropriate capacity factors governing the energy system modeled via

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[8] As per Jacobson, both papers serve as the foundation of his Expert Report.

[9] A capacity factor is the ratio of actual production over a given time horizon, divided by the maximum possible (i.e., full capacity) production for the same period.

[10] As an illustrative example, consider the capital costs of a plant are $1 million dollars a year. At full capacity, the plant can output 1,000 units of product per year. If the plant operates at 100% capacity, the per unit capital costs are $1,000/unit, but at 10% capacity, the per unit capital costs are $10,000/unit. At lower capacities, there are fewer units of production across which to spread the same capital costs.

LOADMATCH in Jacobson et al. (2015b). This misalignment between his 2005 and 2015 analyses results in an underestimation of the hydrogen storage system costs by a factor of 5.26 for Jacobson's et al (2015) high value case, while the underestimation of his low value case is 10[11]. Jacobson's contention on page 4 in his Expert Report that "Our research further finds that the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost …" is based in part on this underestimation.

- **The cost of capital used in Jacobson's analysis is underestimated by a factor of approximately three to four**. Jacobson cites to Jacobson et al. (2018), which uses figures of one to three percent as estimates of the cost of capital for hydrogen storage.[12] In my view, this rate is too low. As explained in section 4.5.1, reasonable values for the cost of capital are 6.2 to 7.7 percent. Benchmarking Jacobson's stated costs of capital of one to three percent against more realistic values of 6.2 to 7.7 percent reveals that Jacobson underestimates the cost of the hydrogen storage system by a factor of 1.6 for Cases A and C.

- **The multiplier factor applied to the major pieces of equipment in the hydrogen storage system is too small.** As described in section 4.5.2, the factored estimation method is a standard methodology for conducting engineering cost estimates. Factors are applied to the capital cost of major pieces of equipment to determine a total project capital cost. In section 4.5.2, I itemize the factors that inform an engineering cost estimate. Briefly, these factors cover installation, supporting facilities, engineering services, contingencies, owner's costs, and interest during construction. The factors vary by project, but for a chemical process like hydrogen production, factors in the range of 3 to 5 are typical (Rudd and Watson, 1968). Jacobson et al. (2018) provides costs for only 3 capital items: the electrolyzer, the compressor, and the storage tanks. Jacobson applies only one factor, an "installation factor" of 1.2 to 1.3[13]. I believe that Jacobson fails to include all the other items listed above in his cost estimation. In my view, Jacobson's failure to include the full suite of relevant cost items results in an underestimation of the hydrogen storage system costs by a factor of 3.0.

As shown in Appendix C, my calculations indicate that correcting for these errors and omissions raises the "Case A" hydrogen system cost estimated in Jacobson et al. (2018) by a factor of 11.8. Further, I calculate that this correction corresponds to an increase in the overall energy costs of the entire WWS system estimated in Jacobson et al. (2018) Case A by 49%. In my view, Jacobson severely underestimates the costs, and electricity cost impacts, associated with the hydrogen storage system. Specifically, my calculations do not support Jacobson's assertion that: "our research further finds that the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost …" (Expert Report, page 4).

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[11] Details in Appendix C, Table C-3.

[12] Jacobson et al. (2015b), which relied on Jacobson et al. (2005), used a range of 6 to 8% for cost of capital. As explained in Appendix C, Jacobson et al. (2015b) also underestimated costs, but cost of capital for the hydrogen storage system was not an issue.

[13] Jacobson et al. (2015b) via Jacobson et al. (2005) provides costs for the same three equipment items, but uses no factors at all. They do state that the electrolyzer capital cost they give is an installed cost.

In addition to underestimating the cost to operate the hydrogen storage system, Jacobson omits analysis of the costs downstream of the hydrogen production plant in his Expert Report and supporting papers. Specifically, Jacobson omits: (1) costs associated with infrastructure necessary to transport the hydrogen to the end-user; and (2) costs incurred by end-users to convert their operations from fossil fuels to hydrogen in their operations. Further, Jacobson offers insufficient analysis as to how transformation of the various sectors to hydrogen would occur. Transforming parts of the economy to hydrogen has been proposed for decades, but little progress has been made in the United States; Jacobson's proposal for the use of hydrogen is theoretical and offers insufficient details to suggest a realistic path forward.

4.2.1.b Assessment of Jacobson's Modeling of Underground Thermal Energy Storage (UTES)

UTES is the largest non-hydrogen storage option employed in Jacobson et al. (2015b). I assessed UTES, as proposed by Jacobson et al. (2015b). My assessment indicates that Jacobson fails to adequately demonstrate the practicality and feasibility of UTES on a scale necessary to achieve a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030. In my view, Jacobson fails to adequately document the full suite of costs associated with UTES; and, for costs that Jacobson cites, he fails to adequately demonstrate cost reasonableness.

Specifically, my review of Jacobson's cost analysis of UTES reveals the following flaws:

1) Jacobson fails to adequately document the sources of UTES capital costs used in his modeling;
2) The capital costs used by Jacobson for UTES are underestimated (see Appendix D for details);
3) Jacobson's "cost of capital" inputs for estimating UTES costs are unrealistically low; and
4) Jacobson's UTES costs rely on inputs based on a "greenfield" or "newbuild" project akin to the Drake Landing Solar Community (DLSC). In reality, existing homes and communities will need to be retrofitted for UTES. In my view, the retrofit of existing homes and communities will be more costly than a "greenfield" or "newbuild" situation, and likely result in the stranding of existing energy infrastructure assets.

In my expert opinion, and for reasons I discuss in more detail below, UTES is not a viable option for large-scale energy storage in the manner envisioned by Jacobson in Jacobson et al. (2015b) and Jacobson et al. (2018),[14] and by extension in his Expert Report.

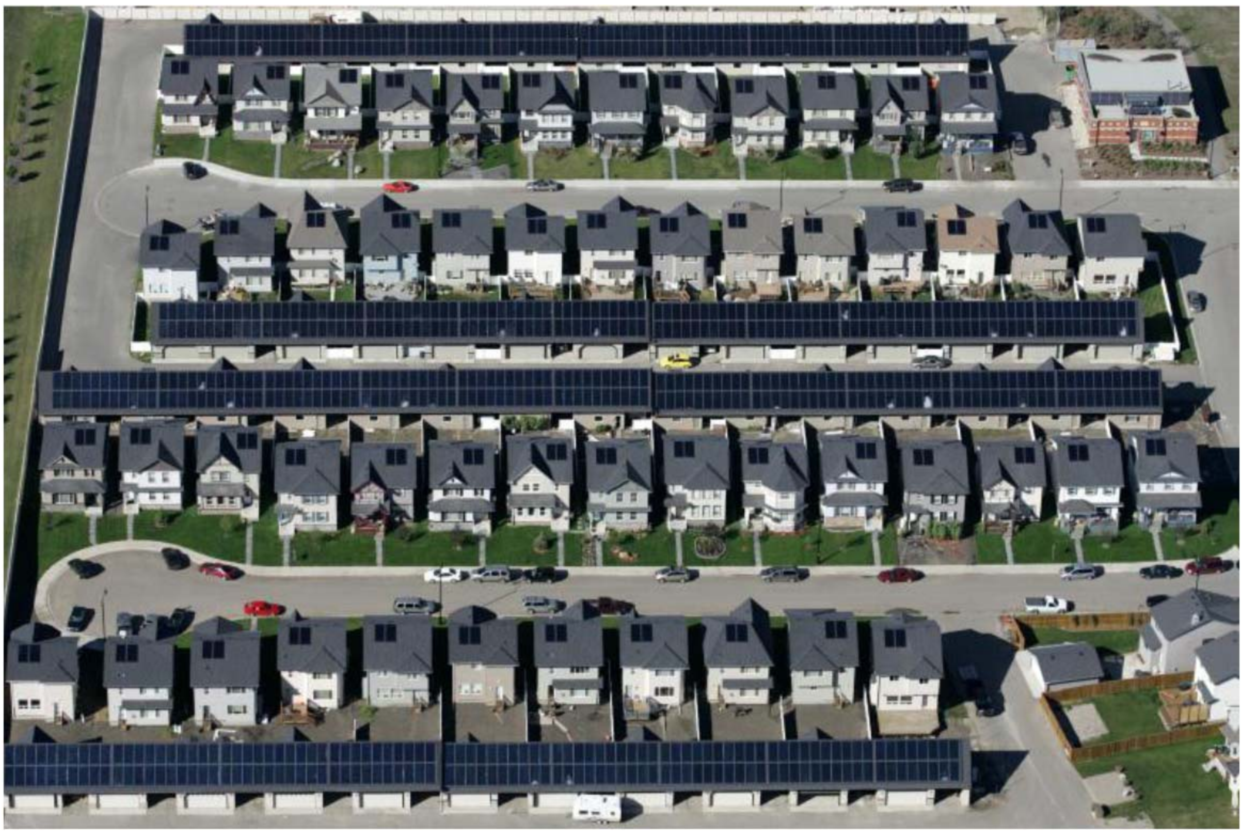
In his Expert Report, Jacobson cites to Jacobson et al. (2015b), which states on page 15060: "All building air- and water-heating coupled with storage uses underground TES (UTES) in soil. UTES storage is patterned after the seasonal and short-term district heating UTES system at the Drake Landing Community, Canada [Sibbitt et al., 2012]." This assertion indicates that

[14] The costing methodology for UTES in Jacobson et al. (2018) is identical to that in Jacobson et al. (2015b) with the exception of the cost of capital, which was lowered from 3 (1.5-4.5)% to 2 (1-3)%.

Jacobson's basis for UTES deployment and functionality is the Drake Landing Solar Community (DLSC), a planned community of 52 homes in Canada.

Based on this concept, Jacobson assumes that 85% to 95% of all air and water heating in the United States will be realized from energy stored in UTES.[15] Achieving this objective requires UTES systems to be retrofitted to tens of millions of homes in the United States. For reference, a picture of DLSC is included below as Figure 3. The picture shows the large area required for solar thermal panels. It also shows a lack of trees in the community, as this would block sunlight. For efficiency, homes in DLSC are spaced closely together. Not pictured, but present, are the 144 boreholes in the community that give access to the underground storage reservoir.

Figure 3. Photo of the Drake Landing Solar Community



Source: Sibbitt et al, (2012).

Jacobson offers insufficient justification or analysis to support his claim that 85% to 95% of all air and water heating in the United States can be realized from energy stored in UTES. Neither in his Expert Report, nor in his articles underpinning his Expert Report, does Jacobson address questions as to whether DLSC can be replicated on a large scale within the United States. Specifically, Jacobson provides no response to:

[15] Jacobson et al. (2015b) Table 1, p.15061, Column titled "(4) percent of load that is flexible (F) or coupled with TES (S) or used for H2 (H) (%)," all rows titled "Air Heating," and "Water heating".

- What are the geological requirements for the UTES storage reservoir? What percentage of neighborhoods in the United States can meet these requirements?

- How can the existing neighborhoods and residential areas be retrofitted or rebuilt to facilitate UTES? How will UTES be implemented in densely-populated neighborhoods, multifamily homes, apartment buildings, and high-rises? How will UTES be deployed in wider neighborhoods with multi-acre lots, or rural communities?

- Will citizens accept the aesthetics of treeless residential areas with many solar panels? Will existing trees need to be cut down and, if so, what will be the environmental, human health, and climate change-related impacts?

- What modifications and retrofits will be needed in existing homes to interface with the UTES system? Who will finance and pay for these retrofits? Will retrofits be mandatory?

In my view, these issues and questions are not minor, esoteric concerns. Jacobson fails to adequately address these concerns in the papers that serve as the basis of his Expert Report. Specifically, in order to achieve a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030, Jacobson relies on storage, a substantial proportion of which is UTES, to ensure that electricity supply meets electricity demand at all times. In my view, Jacobson fails to address the practicability and feasibility of such large-scale storage in his Expert Report or in the underlying literature that he cites in support of his analysis.

In addition to ignoring issues of practicability and feasibility, Jacobson underestimates the costs associated with large-scale deployment of UTES. Notably, DLSC, the example upon which Jacobson relies, was highly subsidized by the Canadian government. "The project added $7.1 million (over $136,000 additional per home) to the development's initial capital cost, which was only feasible due to financial incentives from the federal and provincial governments."[16] In my view, the retrofit cost of $136,000 per home is prohibitively expensive. Jacobson offers no comment on how UTES systems will be financed, or whether a government subsidy cost will be borne by the United States (Federal, States and/or Municipalities) in order to finance myriad similar communities nationwide.

In his Expert Report, Jacobson cites to Jacobson et al. (2015b), which estimates UTES cost. As shown in Appendix D, I recalculate the cost of UTES using capital costs and cost of capital inputs that I believe are more appropriate than those used by Jacobson. My recalculation raises Jacobson's estimated UTES cost nearly sevenfold on a cents-per-kilowatt-hour basis relative to the figure reported in Jacobson et al. (2015b). Based on my recalculation, I estimate a corresponding increase in overall base case energy costs of over 11% from those reported as "2050 total LCOE" in Jacobson et al. (2015b), Table 2, page 15063.

In summary, I believe that Jacobson fails to support his argument that UTES can be reasonably and practicably deployed on a large scale in the U.S. And, in my view, Jacobson has underestimated the costs associated with retrofitting the U.S. to UTES.

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[16] "Combining Our Energies: Integrated Energy Systems For Canadian Communities," Report of the Standing Committee on Natural Resources, House of Commons, Canada, pg. 25 (2009). http://www.ourcommons.ca/Content/Committee/402/RNNR/Reports/RP3982433/rnnrrp04/rnnrrp04-e.pdf

4.2.2 Assessment of Jacobson's Modeling of Demand Response

The term "demand response" refers to a varied set of mechanisms and behaviors by which electric utilities and customers (electricity users) work to adjust the demand for power. One example is for utilities to offer customers financial incentives to postpone electricity-consuming tasks until periods when demand is lower. Another example is to allow utilities to control certain loads, such as air conditioners or water heaters, to help align electricity supply to electricity demand. By adjusting the demand for power in his model, Jacobson relies on demand response to help ensure grid reliability. Manipulating demand is a key mechanism used by Jacobson to match electricity supply and demand at all times, which is essential to Jacobson's premise that a 100% WWS system by 2050 is technically feasible.

In his Expert Report, Jacobson relies on Jacobson et al. (2015b) and Jacobson et al. (2018) as the bases for his assumptions regarding demand response[17]. The sectors that make up the largest proportion of demand response are transportation and industrial, and these are the focus of my assessment. I reviewed Jacobson et al. (2015a) and Jacobson et al. (2018), and I conclude that Jacobson fails to justify his assumptions about the amount of demand response available, and fails to account for the costs associated with such response. In my view, Jacobson overestimates the amount of demand response available. A summary of my analysis of the transportation and industrial sectors follows.

For the transportation sector, Jacobson assumes that 41.4% of the load[18] is subject to demand response. Because Jacobson assumes that 43.6% of transportation load goes to hydrogen production for fuel cell vehicles, nearly three-quarters of all electric vehicles are assumed to be flexible in the timing of their fueling[19]. The time of the greatest surplus electricity in the 100% WWS system is during the solar supply peak. As such, fueling of electric vehicles will need to occur primarily during daylight hours. The feasibility of this fueling structure depends on: (1) whether the American driving public will be able and willing to adhere to this timing; and (2) whether the required infrastructure exists to support fueling this many vehicles at this time of day. Specifically, to charge most electric vehicles in the daytime, when most people work, will require electric charging stations for most parking spaces in most parking garages and lots across the U.S. In his Expert Report, Jacobson does not comment on the practicality of such a large change in infrastructure, nor does he provide insight into what this infrastructure will cost, or who will pay. In addition, Jacobson offers no analysis to support the feasibility of nearly 75% of electric vehicles having flexible fueling schedules that fit with times of excess power generation. He neither offers evidence, nor cites to any studies, to support his assumption that the majority of

[17] In Jacobson et al. (2015b), demand response is included as part of what is termed "flexible load", which is defined as load that can either be supplied from storage or shifted in time. This shifting in time is demand response. Because demand response is aggregated with supply from storage in the paper, one cannot quantitatively determine exactly how much demand response is available in each sector.

[18] Load is a term for devices that draw power from the grid. As used here, it is synonymous with demand. Jacobson et. al (2018), p. 243, Note to table 3 indicates: "41.4% of the transportation load [is assumed to be subject to demand response]."

[19] Since 43.6% of transportation load is covered by hydrogen, the 56.3% is left over. If all this was used by electric vehicles, then the percent of electric vehicles that have flexible loads are 41.4/56.3 = 73.5%. Jacobson et. al (2018), p. 243, Note to Table 3 indicates: "43.6% of the transportation electric load is used to produce, compress, and store H_2 ahead of its use."

the American driving public will abide to this schedule. Finally, Jacobson omits the cost for the required infrastructure in his costing of the 100% WWS system.

For the industrial sector, Jacobson cites to Jacobson et al. (2015b) and Jacobson et al. (2018), which states: "70% of high-temperature industrial load" is subject to demand response.[20]

Jacobson provides insufficient corroborating evidence to support this assumption. Based on numbers provided in Jacobson et al. (2015b) Table 1, I calculate that this load represents a little over 60% of the total industrial sector.[21] Based on my direct professional experience with pulp and paper mills, ammonia plants, chemical plants, refineries, petrochemical plants, and cement plants, I disagree that 60% of the load of the industrial sector can be subject to demand response. Given the capital intensive nature of plants in these industrial sectors, the cost of idling equipment and associated labor limits industry's ability to alter demand response. Jacobson offers no details supporting his assumptions beyond quoting a National Research Council report[22] that states: "In combination with peak-load pricing for electricity, energy efficiency and demand response can be a lucrative enterprise for industrial customers." Jacobson fails to bridge the divide between this statement and his assumption that over 60% of industrial load can respond to demand. I agree that demand response is an important load balancing tool. However, the utility of demand response is predicated on how much is possible, and at what cost. Jacobson fails to address either in his Expert Report.

In summary, I conclude that Jacobson does not justify his assumptions about the amount of demand response available, nor does he account for the associated costs. Further, in my view, Jacobson overestimates the amount of demand response available.

4.2.3 Assessment of Jacobson's Modeling of Hydroelectric Power

The water in dams behind hydroelectric plants are a vast reservoir of energy storage. If hydroelectric plants can be dispatched at will, then they are extremely valuable in matching electricity supply and demand at all times. However, there are constraints that limit the usefulness of hydroelectric power's role in terms of load matching. First, there is an installed capacity that sets the absolute maximum power that hydroelectric can provide at any one time (referred to by Jacobson in his Expert Report as the "peak[23] hydropower discharge rate"). Second, there are constraints on the dispatch of hydroelectric dams for a variety of reasons, including environmental concerns and water use issues. These constraints limit the ability to flexibly dispatch hydroelectric power as a load balancing tool.

[20] This is stated in Jacobson et al. (2018) in the note to Table 3 on page 243, and the Supporting Information on page 6.

[21] Per Jacobson et al. (2015b) Table 1, Column "(3) Percent of sector load (%)", Row "Hi-T/chem/elec procs," 87.19% of the industrial sector load appears to be high temperature, chemical, or electrical processes. Multiplying 87.19% by the 70% of high-temperature industrial load assumed to be subject to demand response per Jacobson et al. (2018) yields 61.03%.

[22] National Academy of Sciences, National Academy of Engineering, National Research Council (2010) Real Prospects for Energy Efficiency in the United States (National Academies Press, Washington, DC), p 251.

[23] While Jacobson uses the term peak hydropower discharge rate in his Expert Report, it is synonymous with the term maximum hydropower discharge rate used in Jacobson et al. (2018).

Specifically, Jacobson's decision to increase the peak hydropower discharge rate in his model (discussed below) has been subject to debate and criticism. In my view, in his models, Jacobson has overestimated the role of hydroelectric power in balancing supply and demand to achieve a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030. Specifically, in my view, Jacobson fails to apply appropriate capacity constraints to address the practical realities of how much and when hydroelectric power can meet energy demand. [24]

In his Expert Report, Jacobson relies on Jacobson et al. (2015b) and Jacobson et al. (2018) to explain his use of the peak hydropower discharge rate. In Jacobson et al. (2018) page 238, Jacobson writes:

> "In [Jacobson et al. (2015b)], it was not made clear in the text but was evident from Fig. 2b, S4b, and S5b that the maximum possible hydropower discharge rate in the continental U.S. was increased by a factor of ~15 relative to the near-present-day maximum discharge rate by adding turbines without a corresponding change in annually averaged hydropower energy output."

Furthermore, Jacobson explains how this constraint is handled in his updated simulations:

> "for North America in Case B, the maximum discharge rate is allowed to increase up to only 2 times the near-present-day value. In Cases A and C, here, zero increases in hydropower turbines are allowed for any region."

Finally, Jacobson discusses cost:

> "[Jacobson et al. (2015b)] further neglected the cost of the additional hydropower turbines, which were subsequently calculated as ~3% of total energy costs. Here, for Case B, for North America, they are ~0.32% of the total energy cost due to the lesser increase in the hydropower maximum discharge rate." (All quotes from Jacobson et al. (2018) page 238.)

In Jacobson et al. (2018), Jacobson claims that in Jacobson et al. (2015b) the peak hydropower discharge rate was raised by a factor of 15, adding about 3% to total energy costs for the 100% WWS energy system. Jacobson neglected to include this change in energy costs in Jacobson et al. (2015b). In Jacobson et al. (2018), Case B raises the peak hydropower discharge rate by a factor of 2, adding about 0.32% to total energy costs for the 100% WWS energy system, while Cases A and C do not raise the peak hydropower discharge rate.

I have several concerns regarding the feasibility of Jacobson's assumption to increase the peak hydropower discharge rate. First, Jacobson has not shown that there is enough room at existing dams. Second, even if sufficient space exists, Jacobson has failed to show that the turbines can

[24] Ken Caldeira, a scholar with the Carnegie Institution for Science at Stanford University, wrote a detailed blog analyzing Jacobson et al. use of hydroelectric power, concluding: "Whether you call failure to impose a suitable capacity constraint on maximum hydro generation in each time period a "modeling error" is up to you, but that would seem to be an entirely reasonable interpretation based on the available facts." https://kencaldeira.wordpress.com/2018/02/28/mzj-hydro-explainer/amp/

dispatch at those increased rates. In addition, there are myriad factors that restrict discharge rates. In my professional experience, these factors arise from environmental concerns and from competitive uses for the water, such as irrigation. Finally, there is the matter of cost. In Jacobson et al. (2018), Jacobson claims a 3% increase to total energy costs for the 100% WWS energy system when referring to the case presented in Jacobson et al. (2015b). My assessment is that this estimate is too low. In my view, the estimate presented in Clack et al. (2017) of a 24% increase is more realistic, but my experience suggests that even this estimate may be too low. In summary, Jacobson makes assumptions about the possibility of increasing peak hydropower discharge rates, but offers no technical justification. He does not present a single study of an existing dam to show whether this increase is even feasible.

My conclusions are similar to Clack et al. (2017) regarding Jacobson's lack of constraints on the dispatching of hydroelectric power:

> "Achievable peak hydropower output is likely to be significantly smaller than the theoretical maximum …. This is because the total output of hydroelectric facilities is limited by overall river flows and further constrained by environmental considerations and other priorities for water use (e.g., navigation, irrigation, protection of endangered species and recreation). These constraints currently prevent all hydroelectric capacity from running at peak capacity simultaneously …. In addition, a portion of U.S. hydropower facilities are "run-of-river" facilities without the ability to store water for on-demand power production behind the dams, and still more facilities have minimum and maximum flow rates imposed for environmental reasons that restrict their operating flexibility. Recent years have seen major environmental initiatives to restrict hydropower output and even remove dams; the courts and political processes have been receptive to these efforts and all indications point to even more restrictions in future." (Clack et al., 2017, SI, page 3)

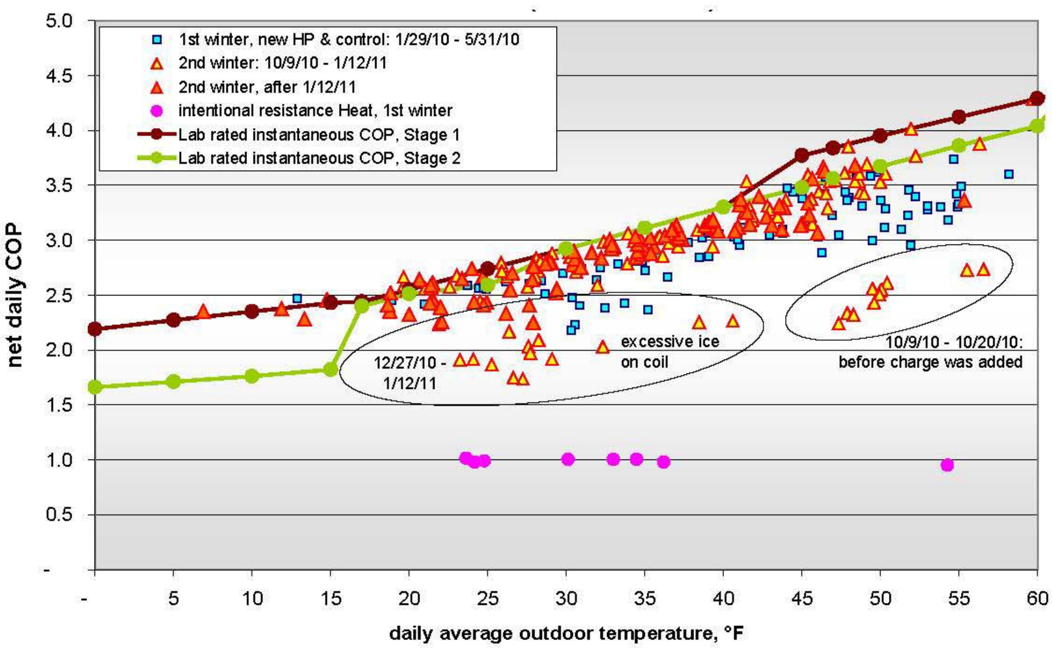
The dispatch of hydroelectric power is an important mechanism used by Jacobson in his LOADMATCH model to balance electricity supply and demand at all times. Constraints on how hydroelectric power can be dispatched appear to be missing from the model. The net effect of Jacobson over relying on hydroelectric power to balance load, is an underestimation in the need for other storage options, resulting in an underestimation of costs for his 100% WWS energy system and weakening his claim of technical feasibility.

4.2.4 Assessment of Jacobson's Modeling of Extreme Conditions

To demonstrate an energy system is technically feasible, it must be proved out at extreme weather conditions, because these are the moments at which there is high energy usage, high stress on the performance of energy systems, and therefore, the highest probability of failure. Jacobson's Expert Report relies on Jacobson et al. (2015b) and Jacobson et al. (2018) as the bases for his opinions. My assessment of Jacobson et al. (2015b) and Jacobson et al. (2018) suggests that simulated testing at extreme conditions was not done by Jacobson. Notably, from Jacobson et al. (2015), page 15061: "The 2050 annual cooling and heating loads (Table 1) are distributed in LOADMATCH each 30-s time step during each month of 2050–2055 in proportion to the number of cooling- and heating-degree days, respectively, each month averaged over the United States from 1949 to 2011." In fact, Jacobson relies on historically average temperatures for each month in his model. In my view, the use of these historically average temperatures does not capture extreme weather events, because, among other reasons, smoothing these temperatures over a month's time horizon eliminates the spikes in temperatures, and the associated spikes in energy demand.

An example of extreme weather conditions is bitter cold over much of the US for an extended period of time, as occurred during the polar vortex (January 2014) or the cold snap last winter (December, 2017- January 2018). Temperatures were well below average by 10 degrees, 20 degrees, or even more in some places.[25] The obvious direct effect of lower temperatures is the demand for more heating, as well as strain on the performance of energy systems. For example, the efficiency of heat pumps (see Figure 4 below) is measured by the coefficient of performance (COP), which declines substantially in the cold. At 0^{o}F, a heat pump requires about twice the electricity per unit of heat delivered as that required at 40^{o}F. At subzero temperatures, which were present during these cold snaps, the efficiency degrades even more.

Figure 4. Net Daily Coefficient of Performance (COP)



Source: R.K. Johnson, "Measured Performance of a Low Temperature Air Source Heat Pump", National Renewable Energy Laboratory Report, page 14 (September 2013). Reproduced from Figure 8. Net daily COP as measured on site is compared to the heat pump's laboratory-rated efficiency. The laboratory data are established in an environmental chamber, with the heat pump fully warmed up and operating under steady-state conditions.

Battery performance also degrades in cold conditions. Jacobson's transition to a 100% WWS system by 2050 is predicated on the electrification of the passenger car fleet, which will rely on batteries for sustained performance. Battery performance will be substantially affected in

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[25] For information on the January 2014 polar vortex, see Nick Wiltgen, "Deep Freeze Recap: Coldest Temperatures of the Century for Some," weather.com, January 10, 2014, available online at: https://weather.com/storms/winter/news/coldest-arctic-outbreak-1990s-midwest-south-east-20140103. For information on the 2017-2018 North American cold wave, see "Record-breaking cold sweeps US in first days of 2018," *Christian Science Monitor*, January 2, 2018, available online at: https://www.csmonitor.com/USA/2018/0102/Record-breaking-cold-sweeps-US-in-first-days-of-2018.

extreme weather conditions. Specifically, more electricity will be required for each mile traveled during such conditions. Based on the materials available to me, there is no indication that these types of feedbacks are simulated in Jacobson's model.

In summary, Jacobson, did not run simulations of extreme conditions in LOADMATCH. In addition, LOADMATCH is static; it does not automatically adjust the performance of different components of Jacobson's proposed energy system for changes in meteorological conditions. I believe that without correctly simulating and testing for extreme weather conditions in LOADMATCH, Jacobson cannot claim that the 100% WWS energy system matches electricity supply and demand at all times, which is an essential requirement for a "technically feasible" energy system.

4.2.5 Summary: Jacobson fails to demonstrate that his proposed energy system can match electricity supply and demand at all times, a requirement of technical feasibility.

Intermittency will be a major challenge to any energy system that relies heavily on intermittent renewable energy sources, such as Jacobson's 100% WWS energy system. Properly functioning electricity systems must match demand with supply at all times. Jacobson proposes that energy storage, demand response, and dispatching of hydroelectric power solve the intermittency problem for his 100% WWS energy system. However, in my expert opinion, Jacobson fails to adequately demonstrate the technical feasibility of his proposed system because his assumptions regarding energy storage, demand response, and hydroelectric power dispatch are unrealistic, unsubstantiated, or both. Specifically, I find that:

- ***Hydrogen Storage.*** Jacobson's costs for the hydrogen storage system are underestimated by at least a factor of ten and the costs and barriers for transforming the needed to parts of the transportation and industrial sectors to hydrogen use are not addressed.

- ***Underground Thermal Energy Storage (UTES).*** Jacobson fails to adequately demonstrate the practicality and feasibility of UTES on the scale envisioned. Beyond matters of practicality, Jacobson fails to adequately document the costs associated with UTES and underestimates those cost by at least a factor of 7.

- ***Demand response.*** Jacobson does not provide sufficient justification for his assumptions about the amount of demand response available nor does he account for its cost. Further, he substantially overestimates the amount of demand response available.

- ***Dispatching of hydroelectric power.*** Jacobson makes assumptions about the possibility of increasing maximum hydropower discharge rates, but offers no technical justification; nor does he present even a single study of an existing dam to show whether this increase is even feasible. There is no indication that Jacobson acknowledges constraints on the dispatch of hydroelectric power, let alone incorporated them into his model.

- ***Simulation of extreme weather conditions.*** There is no indication that Jacobson simulates the ability of his proposed energy system to match electricity supply and demand during extreme weather conditions, at which times there is the highest probability of failure.

Given these flaws, it is my expert opinion that, contrary to what is stated in his Expert Report, Jacobson has neither demonstrated that his 100% WWS energy system is technically feasible, nor that the U.S. electric power grid with 100% WWS can stay stable at direct energy costs similar or less than today's costs.

4.3 Finding #3: Jacobson's proposal for long-distance electricity transmission is unsubstantiated, fails to illustrate or validate its technical feasibility, and underestimates its costs.

Jacobson's proposed energy system considers the United States (excluding Alaska and Hawaii) as a whole. Given that weather conditions will vary from region to region and State to State, long-distance electricity transmission infrastructure is necessary to move generated and stored electricity in one region to another to ensure that there is always adequate supply to meet demand, regardless of local conditions. In his Expert Report on page 2, Jacobson states that: "A 100% WWS system would also require … an expanded transmission and distribution system." Based on my analysis of this component of Jacobson's modeled 100% WWS system, I conclude:

1) The level of detail supplied by Jacobson is inadequate,

2) Jacobson does not address critical issues regarding siting and permitting,

3) Jacobson is silent on policy and governance issues regarding the grid, despite proposing a system that likely is incompatible with the current governance of the grid, and

4) Jacobson substantially underestimates the costs associated with an expanded transmission and distribution system.

I summarize the bases for my opinion on these issues below, and provide additional details in Appendix E.

First, the level of detail supplied by Jacobson for his proposed long-distance transmission system is inadequate. Jacobson's proposal is highly conceptual, and falls short on details. Specifically, Jacobson does not present any system designs or simulations of the long-distance transmission grid. Jacobson's analysis appears to be based on two primary assumptions: (1) the percent of wind and solar requiring extra transmission; and (2) the length of the extra transmission lines. Relying on these parameters, Jacobson assumes in his LOADMATCH model that all generated electricity can be distributed freely around the country, with no constraint or difficulty.

Further, Jacobson does no modeling or simulations of the transmission system to:

- Test or validate that his primary assumptions regarding the percent of wind and solar generation requiring extra transmission, or the length of the extra transmission lines, are valid;

- Confirm that congestion[26] on the grid will not pose a problem in his proposed energy system; and
- Validate his assumed 40 percent capacity factor (see Appendix E, Issue #5).

Second, Jacobson is silent on the challenges associated with siting and permitting new transmission lines. A recent *Technology Review* article commented on current proposals for new long-distance transmission lines by noting: "all of these [proposals] are moving through the approvals process at a dawdling pace."[27] One recent example of the types of challenges inherent to the siting and permitting of new transmission lines is the Northern Pass project, a 192-mile transmission line project to bring hydroelectric power from Canada to New Hampshire and New England.[28] According to the Department of Energy,

> "Since it was first proposed in 2010, the $1.6 billion Northern Pass project has been subject to multiple layers of federal and state government permitting regulations, a nearly 4,000 page Environmental Impact Statement, and adjusted its planned route in response to input from local communities as well as federal and state permitting agencies."[29]

In early 2018, the state of New Hampshire rejected the project's permit, jeopardizing the entire project after eight years of development.[30] Jacobson ignores these types of difficulties and challenges in his Expert Report. At a minimum, addressing such issues adds to project costs and slows down implementation timelines. In the worst case, a failure to resolve such issues may result in project cancellation.

Third, Jacobson's analysis fails to acknowledge the current realities of the U.S. energy grid. Today, the U.S. grid is divided into three distinct interconnects, with essentially no electricity moving between them. Within these interconnects, the grid is subdivided into Independent System Operators (ISOs) established by the Federal Energy Regulatory Commission (FERC). The ISOs coordinate, control, and monitor the operation of the grid within their geographical jurisdictions.

Jacobson's LOADMATCH model ignores the existence of these interconnects, and associated complexities. Instead, Jacobson assumes that electricity moves freely between and across interconnects, with no mention of policy or governance concerns. Further, Jacobson neither comments on whether the current system, with three interconnects and multiple ISOs is compatible with his proposed 100% WWS system, nor addresses the costs and complexities

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[26] Congestion in transmission lines is similar to highway congestion. Like a highway, there is a capacity of the lines to transmit electricity. If the load is too large, only a fraction will be transmitted, opening the possibility that demand will not be satisfied. There are models available to simulate the operation of transmission lines and identify areas that could have congestion. LOADMATCH does not do this.

[27] James Temple, "How to Get Wyoming Wind to California, and Cut 80% of U.S. Carbon Emissions," *Technology Review* 121 (2): 16-17 (2018).

[28] See http://www.northernpass.us/project-overview.htm for additional information on the Northern Pass project.

[29] https://energy.gov/articles/department-energy-approves-presidential-permit-northern-pass-transmission-line-project

[30] Jon Chesto and David Abel, "N.H. rejects Canada-Mass. power lines," *Boston Globe*, February 2, 2018.

associated with transitioning these interconnects to his proposed system. In my expert opinion, current grid governance is incompatible with Jacobson's proposed 100% WWS system, and would require significant modifications to function within Jacobson's model. Jacobson is silent on the changes likely to be required, how long such changes will take to implement, and the political feasibility of such changes.

In addition to the aforementioned conceptual issues, my review of Jacobson's underlying calculations suggests that he has substantially underestimated the costs for long-distance transmission. As I detail in Appendix E, I believe that Jacobson's modeling underestimates costs for long-distance transmission by at least a factor of four, and it could be much higher. I summarize two of the biggest issues below:

- Jacobson's estimates for the capital costs associated with long-distance transmission infrastructure are questionable. As described in Appendix E, I compare Jacobson's capital cost estimates with estimates from recent projects, including the Northern Pass project. My analysis reveals a material discrepancy that compromises the reliability of Jacobson's cost estimates. Specifically, when compared with the Northern Pass project, Jacobson's capital cost estimates are underestimated by an order of magnitude (i.e., a factor of 10 or more).

- Jacobson's calculations underestimate costs when converting the capital costs of long-distance transmission projects to electricity costs. As I described for other parameters of Jacobson's analysis, in my view, these underestimates share similar causes: (1) the capacity factor used by Jacobson appears too high; (2) the cost of capital factor used by Jacobson appears too low; and (3) it appears that Jacobson omits operations and maintenance (O&M) costs associated with long-distance transmission lines.

In my expert opinion, Jacobson fails to adequately define his transmission system, and he does not offer any modeling to show that his proposed system will work as advertised. Further, Jacobson does not address issues regarding siting and permitting, and he is silent on policy and governance issues regarding the U.S. energy grid. Finally, as with the storage technologies, Jacobson underestimates the costs associated with an expanded transmission and distribution system.

In my view, Jacobson has failed to justify the assumption in his LOADMATCH model that electricity can be freely moved around the country. Notably, if there are constraints on the ability for electricity to move freely across the U.S. energy grid, then greater importance is placed on effective storage and/or demand response techniques. If electricity cannot, or does not, move freely across regions of the United States, then additional storage and/or demand response will be required. As discussed above, Jacobson fails to evince effective storage or demand response in his Expert Report. The collective effect of these failures in transmission, storage, and demand response is that energy demand will not match energy supply at all times, and the energy system will fail.

4.4 Finding #4: Jacobson ignores the necessary provision of essential grid services, such as frequency control, operating reserves, and grid security, in his modeling and cost estimates.

Energy grids are complex mechanisms that require many components to ensure that electricity flows, matching supply with demand. Many grid services are required to prevent blackouts and avoid damage to machinery attached to the grid. Jacobson omits consideration of these services from his analyses.

Frequency control[31] is essential for the grid because poor frequency control will damage machinery, result in suboptimal performance, and potentially disrupt the whole grid. Wind and solar power are asynchronous generators. At present, systems with high penetrations of asynchronous generators are unproven to maintain good frequency control. In his Expert Report, Jacobson cites to Jacobson et al. (2015b) and Jacobson et al. (2018) as the bases for his proposed energy system. My assessment of both papers indicates that neither Jacobson et al. (2015b) nor Jacobson et al. (2018) include any analysis or modeling that demonstrates that the proposed 100% WWS energy system can maintain frequency control.

Although a statement in the supplemental information to Jacobson et al. (2015b) contains a list of components that potentially can assist with frequency control, such as energy storage and demand response, as I discuss above, there is no analysis or modeling performed that demonstrates that these components are sufficient for effective frequency control in the proposed 100% WWS system. As a result, Jacobson's analyses are insufficient to demonstrate the technical feasibility of this aspect of his proposed energy system.

With regard to the grid, "operating reserves" refer to generating capacity available to meet electricity demand in the case of disruptions. Operating reserves are essential to prevent disruptions in energy supply. Because wind and solar are intermittent power sources, operating reserves are of heightened importance given the uncertainty of wind and solar generation. In my view, LOADMATCH and Jacobson's analyses fail to account for this key aspect of grid functionality. Other scholars, including Clack et al. (2017) support this opinion, concluding:

> "…the LOADMATCH model does not provide the provision of operating reserves necessary to maintain reliability in the case of unplanned outages of transmission lines and generation or storage facilities and errors in forecasted wind and solar output and demand. Studies of existing wind and solar projects and experience in power systems with growing shares of variable renewable resources demonstrate that solar and wind energy forecast errors can be significant: for example, errors related to variable output caused by cloud cover and other meteorological conditions that have been documented at coastal and inland solar PV and CSP plants in California." (Clack et al, 2017, supporting information, page 11)

[31] The US grid operates on alternating current (AC) power. AC power is transmitted as sine waves; the frequency is the number of cycles per second of these sine waves. In the US, the grid operates at 60 cycles per second, also called 60 hertz or 60 Hz. Frequency control is required to make sure that the grid operates at the proper frequency.

In my expert opinion, Jacobson's omission of considerations for operating reserves both underestimates the costs of his proposed energy system and renders his analysis inadequate to demonstrate its feasibility.

Lastly, grid security is a top priority of the U.S. Department of Energy and is an identified vulnerability for attacks by foreign agents.[32] Jacobson et al. (2015b) on page 12 of the supporting information note with regard to security only that: "Resiliency and security are lower priority elements but are nevertheless topics of interest as well." These "lower priority elements" do not appear to be modeled by Jacobson in Jacobson et al. (2015b). In my expert opinion, grid security is essential to grid operation – one cannot claim that an energy system is technically feasible and reliable without rigorous analysis of that system's security and resiliency to disruption and attack.

4.5 Finding #5: Jacobson's Expert Report and underpinning analyses do not leverage best practices in cost estimation, leading to a significant underestimation of costs.

My assessment of Jacobson's Expert Report and the sources that underpin its estimates and conclusions reveals a pattern by Jacobson of not conforming to best practices in cost estimation. It is my view, this pattern results in costs being substantially underestimated.

I identify the following repeated flaws and errors, which are cumulative, made by Jacobson[33]:

- The cost of capital used by Jacobson throughout his analyses is consistently, unrealistically low. I conclude that, as a result of this analytic flaw, Jacobson consistently underestimates costs by a factor of 2 to 4.
- Jacobson focuses his cost estimation on the major equipment items, but omits other significant project costs. I conclude that, as a result of this analytic flaw, Jacobson consistently underestimates costs by a factor of 3 to 5.
- Jacobson's choice of capacity factors is erroneous in some instances and undocumented in some others. For example, I conclude that, as a result of these analytic flaws, Jacobson underestimates costs for the hydrogen storage system by a factor greater than 8.
- Jacobson fails to index costs for the hydrogen storage system and long-distance transmission system.
- Jacobson does not consider the macroeconomic impacts of an accelerated program to transform the United States energy systems. These impacts will result in much higher costs for all parts of the energy system.

The effect of these flaws are cumulative, as shown for the example of the hydrogen storage system in Appendix C, Table C-5. I discuss each of these flaws in more detail below.

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[32] Earlier this year, DOE launched the Office of Cybersecurity, Energy Security and Emergency Response to deal with grid security issues. See http://www.insidesources.com/time-doe-lead-electric-grid-security/.

[33] The first and last bullets applies to all technologies costed – generation, storage, transmission, etc. The other three bullets apply primarily to non-generation technologies.

4.5.1 Jacobson's Modeling of the Cost of Capital

In my view, the cost of capital used by Jacobson throughout his analyses is consistently, unrealistically low. Jacobson appears to confuse the *discount rate* with the *cost of capital*. While the discount rate is related to, and may affect, the cost of capital, they are distinctly different parameters. The discount rate describes the time value of money.[34] Whereas, the cost of capital is project-specific and describes the interest rate (or financing cost) that must be paid to raise capital to pay for a specific project. Most capital projects are financed with a combination of debt (loans) and equity (owner investment); in general, the cost of capital is expressed as a weighted average of the cost of debt and equity.

In the table below, I summarize cost of capital figures from Lazard (2017), a source commonly used by industry practitioners. The first column reflects cost of capital figures used by Lazard (2017) in its levelized cost of electricity (LCOE) analyses. The second column reflects alternative cost of capital figures suggested by Lazard (2017) as being potentially more prevalent for North America.

Cost of Capital Parameter	Used in Lazard's LCOE Analysis	Potentially More Prevalent for North America as suggested by Lazard
After-Tax Weighted Average Cost of Capital	7.7%	6.2%
Cost of Equity	12.0%	10.0%
Cost of Debt	8.0%	6.0%

As indicated in the table above, a reasonable range for an after-tax weighted average cost of capital for North America is between 6.2% and 7.7%. In my view, these are the appropriate parameters to use when assessing the cost impacts of financing capital changes to the U.S. electricity system. By comparison, the two published papers cited by Jacobson as forming the basis for his Expert Report, Jacobson et al. (2015b) and Jacobson et al. (2018), rely on a stated "discount rate" of 3% and 2%, respectively.

In his analyses, Jacobson does not differentiate between the discount rate and the cost of capital. In so doing, Jacobson ignores the fact that a discount rate and a cost of capital are different. In Jacobson et al. (2018), Jacobson justifies his use of a low discount rate as an intergenerational discount rate. In my view, it is not appropriate to use an intergenerational discount rate to calculate the financing cost associated with raising capital to fund an infrastructure project. To fund a project similar to those contemplated by Jacobson in his Expert Report, one must be prepared to pay a rate commensurate with the prevailing cost of capital at the time the project is undertaken. In my view, Jacobson's interchangeable use of discount rates with cost of capital rates is incorrect; and, in so doing, Jacobson substantially underestimates costs throughout his analyses. As a result, I believe that Jacobson fails to support his contention that a transformation of the U.S. energy sector to 100% WWS by 2050 is economically feasible.

[34] The time value of money refers to the premise that a dollar today is worth more than a dollar tomorrow, by virtue of the ability to invest today's dollar and realize a financial return on that investment.

In my view, Jacobson further underestimates costs by using relatively long project lifetimes. Jacobson's use of longer lifetimes effectively reduces the annual capital charges of a project, by extending the period over which the project is to be funded. When costing projects, standard industry practice involves the use of economic lifetimes, which are notably shorter than the project lifetimes used by Jacobson. For example, in Jacobson et al. (2018) Table S2, project lifetimes range from 30 to 85 years. As a measure of comparison, Lazard (2017) uses a standard project lifetime of 20 years. The table below compares annual capital charges across differential assumptions for cost of capital and project lifetimes. (For a derivation of the annual capital charge, see Equation 2 in Appendix E.)

Parameter	**Lazard: LCOE Analysis**	**Lazard: More Prevalent for North America**	**Jacobson et al. (2015b): 30-year lifetime**	**Jacobson et al. (2018): 30-year lifetime**	**Jacobson et al. (2018): 85-year lifetime**
Cost of capital	7.7%	6.2%	3.0%	2.0%	2.0%
Project lifetime	20	20	30	30	85
Annual capital charge	10.0%	8.9%	5.1%	4.5%	2.5%

As illustrated in the table above, annual capital charges under Jacobson's cost of capital and project lifetime assumptions are underestimated by a factor of two to four relative to industry-standard assumptions from Lazard (2017). In my opinion, this underestimation is substantial and undermines Jacobson's contention on page 4 in his Expert Report that "Our research further finds that the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost …".

4.5.2. Estimating Total Capital Requirement

An important principle in engineering cost estimation is correctly identifying the capital requirements associated with the design, construction, and operation of an engineered system. Reliably applying engineering cost principles is essential to determine whether a proposed engineered system is technically and economically feasible. In my experience, determining whether a project is feasible will inform whether sufficient financing exists to move forward. I believe that Jacobson, when costing certain proposed changes to the U.S. energy system, errs by assessing costs associated only with major capital equipment items. In so doing, Jacobson fails to accurately apply generally accepted principles in engineering cost estimation, yielding results that are not reliably supported.

Typically, in my experience, practitioners use the "factored estimate" approach[35] to estimate the capital requirements, and, by extension, the financing needs, of a project. The first step in this approach is to itemize and cost the major equipment items. Then, factors are applied to adjust this estimate to account for other project-related costs. By methodically building up these layers of costs, one arrives at the "Total Capital Requirement;" this is the value that must be financed for a project to move forward.

[35] See the classic textbook, Rudd and Watson (1968), as well as a more recent paper, Rubin et al. (2013).

For example, as an engineering practitioner, I begin with the costs of the major equipment items and apply factors to account for labor, and items such as piping, instrumentation, insulation, foundations, buildings, structures, fireproofing, electrical, painting, and clean up to arrive at the "Bare Erected Costs." Then, using the subtotal of bare erected costs, I add estimates for engineering services, as well as process and project contingencies to arrive at an estimate of "Total Plant Costs." Next, I add to the estimate of total plant costs, an estimate of one-time owner's costs, including but not necessarily limited to the cost of feasibility studies, surveys, land, insurance, permitting, finance transaction costs (e.g., debt financing costs). This results in "Total Overnight Costs." Finally, adding in "Interest During Construction" yields the "Total Capital Requirement."

In my view, Jacobson narrowly focuses his cost estimation only on major capital equipment items, excluding cost parameters that are generally accepted by engineering practitioners as necessary to assess the total cost of designing, constructing, and operating a system. Although the ratio of total project costs to capital equipment costs tends to vary by project, in my professional experience, this ratio tends to be in the range of 3 to 5. My opinion is supported by Rudd and Watson (1968). My analysis of the data presented by Jacobson, and the cost estimation methods that he applies, indicate that Jacobson has not reliably and accurately accounted for all of the costs likely to result from his proposed changes to the U.S. energy system. In the case of the hydrogen storage system, I observed that Jacobson uses a total project cost to capital equipment cost ratio of only 1 to 1.3, which is substantially less than that affirmed by experts in engineering cost estimation.

By ignoring the full suite of project costs necessary to transition the U.S. energy system, I estimate that in certain cases Jacobson is accounting only for approximately 20 to 33% of total capital costs, and by extension is substantially underestimating the true cost of his proposed changes to the U.S. energy system.

4.5.3. Determining Capacity Factors

A capacity factor is the ratio of actual production over a given time horizon, divided by the maximum possible (i.e., full capacity) production over that period. A capacity factor informs how effective one is in the use of the capital put into a project. For example, if a power project costs $1,000/kW and the annual capital charge is 10%, then the annual capital costs are $100/kW/yr. There are 8,760 hours per year. So, if the capital is used 100% of the time (i.e., capacity factor of 1), the capital component of the costs would be 1.14¢/kWh[36]. However, if the capital is used only 50% of the time, then the cost would double to 2.28¢/kWh. A capacity factor of 10% yields a cost of 11.4¢/kWh. Therefore, accurate costing is predicated on correct capacity factors.

As previously discussed in section 4.2.1a, I believe that Jacobson erroneously used a capacity factor for hydrogen production that is more than eight times too large. In my view, this error is characteristic of a lack of attention to detail. For example, the capacity factor for hydrogen production is easily calculated from Jacobson's LOADMATCH simulations (see Appendix C, Issue #3). Specifically, the system load for hydrogen production is 180.2 GW, when averaged

[36] $100 kW/yr/(100%*8760hrs/yr) =$0.0114/kWh=1.14¢/kWh

over the year. The maximum load is about 2,000 GW. In my professional experience, one engineers a system for the maximum load, plus a safety factor. For this example, in my professional experience, a typical safety factor of 15% is reasonable. Based on these parameters, the size of the hydrogen production system is 2,300 GW. Therefore its capacity factor is 180.2 GW divided by 2300 GW or 7.8%. Even if we did not include a safety factor, the capacity factor would be 9% (i.e., 180.2/2000). Jacobson uses a capacity factor of 72.5%. As I note above, the lower the actual capacity factor, the greater the cost of electricity. Based on my analysis, I have similar concerns about the capacity factor used by Jacobson in the long-distance transmission system, and believe that Jacobson has overestimated his capacity factor for long-distance transmission (see Appendix E).

In my view, in both cases, Jacobson does not conduct the type of analysis that I would expect as a practitioner in the field to determine reasonable capacity factors.

4.5.4 Indexing Year Dollars

In his Expert Report, Jacobson cites to Jacobson et al. (2015b) and Jacobson et al. (2018), both of which report results in 2013 US dollars. My assessment of these supporting materials indicate that Jacobson made the following errors, which lead to an underestimation of capital costs:

1) The hydrogen storage system costs were excerpted from Jacobson et al. (2005) in 2004 US dollars, and renamed 2013 US dollars in Jacobson et al. (2015b) with no adjustments (see Appendix C, Issue #2).

2) The transmission costs were excerpted from Delucchi and Jacobson (2011) in 2007 US dollars and renamed 2013 US dollars in Jacobson et al. (2015b) and Jacobson et al. (2108) with no adjustments (see Appendix E, Issue #1).

4.5.5 Accounting for Macroeconomic Impacts

In my professional experience, engineering practitioners cannot design, construct, and operate systems in a vacuum. In fact, I often collaborate with economists to ensure that the macroeconomic impacts of an engineered system are appropriately accounted for when modeling transformations to the U.S. energy system. Integrated Assessment Modelling (IAM) is used in the environmental engineering field to ensure that the institutional knowledge of multiple disciplines are integrated to provide a balanced assessment of potential impacts of an engineered system. My work on how to incorporate carbon capture and storage technologies into IAM is a representative example of this approach[37].

The scope of changes proposed by Jacobson for his 100% WWS system is unprecedented both in terms of magnitude and in terms of timing (see section 4.1). In my view, adopting Jacobson's approach will raise demand for a wide assortment of commodities, goods, and services. Labor, steel, and rare earth elements are just a few of examples from a longer list. Absent a

[37] See, for example, McFarland, J.R.and H.J. Herzog, "Incorporating Carbon Capture and Storage Technologies in Integrated Assessment Models," *Energy Economics* **28**: 632-52 (2006).

countervailing surge in supply, increased demand to achieve the immediate scalability envisioned by Jacobson will result in substantial price increases for these commodities, goods, and services. Jacobson errs in his analysis by neither integrating changes in demand (and associated price increases), nor addressing constraints on supply, in his modelling.

As a result, Jacobson underestimates the true cost of transitioning from a predominantly fossil fuel-based energy system to a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030. In addition, he has failed to apply accepted macroeconomic principles in his analysis of whether the "U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost…" (Jacobson Expert Report, page 4).

5. Conclusions

Jacobson's proposed energy system is focused on wind, water, and solar technologies for electricity generation, to the exclusion of nuclear power, carbon capture and storage (CCS), and biomass generation. Others have also proposed all renewable electricity systems; Heard et al. (2017) evaluated 24 studies proposing 100% renewable electricity systems, including that proposed in Jacobson et al. (2015b). Heard et al. (2017) conclude:

> "None of the 24 studies provides convincing evidence that these basic feasibility criteria can be met…(Abstract) This desire to push the 100%-renewable ideal without critical evaluation has ironically delayed the identification and implementation of effective and comprehensive decarbonization pathways. We argue that the early exclusion of other forms of technology from plans to decarbonize the global electricity supply is unsupportable, and arguably reckless." (page 1130)

Intermittent renewables pose major challenges for electricity systems because their generation is controlled by nature, not by the operators of the electricity system. As such, it is critical to have technically feasible, cost-effective storage options to supply electricity to satisfy demand when the sun is not shining and the wind is not blowing. These options are not commercially available today at large-scale. Jacobson proposes some possibilities, such as hydrogen storage or underground thermal energy storage, but they are unproven and Jacobson does not provide an adequate analysis to show they are either technically feasible or cost-effective. In his Expert Report, page 19, Jacobson states:

> "IPCC (2014) further states that, with high penetrations of renewable energy (RE), nuclear and CCS are not efficient (Section 7.6.1.1), "*…high shares of variable RE power…may not be ideally complemented by nuclear, CCS,…*""

The reason for this is the intermittency of renewal sources result in lowering the capacity factors of nuclear and CCS, driving up their costs. However, the exact same phenomenon impacts all capital intensive systems in the electricity system, including energy storage technologies. Jacobson claims his storage technologies can be cost effective, but as documented in this report, he underestimates their capital costs, uses unrealistically high capacity factors, and uses unrealistically low cost of capital. It is ironic that part of his reasoning for rejecting CCS and nuclear technologies applies equally well to rejecting his options for energy storage.

Jacobson's analysis of the mechanisms beyond energy storage that are used to match supply and demand at all times is also flawed.

- Jacobson substantially overestimates the amount of demand response available. He does not provide sufficient justification for his assumptions about the amount of demand response he assumes nor does he account for its cost.

- Jacobson makes assumptions about the possibility of increasing maximum hydropower discharge rates, but offers no technical justification; nor does he present even a single study of an existing dam to show whether this increase is even feasible. There is no indication that Jacobson acknowledges constraints on the dispatch of hydroelectric power, let alone incorporated them into his model.

Electricity must be effectively moved from where it is generated to where it is used. Jacobson's simulations assume that new long-distance transmission lines will solve this problem. However, his proposal provides inadequate details and contains no modeling or simulation to demonstrate that the proposed long-distance transmission framework will work. Further, Jacobson is silent on key issues regarding long-distance transmission, such as siting, permitting, and governance.

Grid services such as frequency control, operational reserves, and grid security are essential to a properly-functioning energy system. Jacobson's modeling and simulations pay little attention to these concerns, and he offers no analysis to support the ability of his proposal to satisfy these essential needs.

Jacobson reports Total LCOE (¢/kWh all energy) for his 100% WWS systems in Jacobson et al. (2015b) in the range of 8.5-15.4¢/kWh, with an average of 11.37¢/kWh; and in Jacobson et al. (2018), Jacobson reports point estimates of 10.51¢/kWh (Case A), 10.09¢/kWh (Case B), and 10.62¢/kWh (Case C). These cost estimates are not believable, because they fail to conform to best practices in cost estimation, including but not limited to modeling the cost of capital, estimating total capital costs, determining capacity factors, indexing year dollars, and accounting for macroeconomic impacts. In a more rigorous assessment, I would not be surprised to see them exceed 50¢/kWh.

Jacobson's proposed timelines for building, installing, and deploying the necessary facilities and infrastructure to transition to his proposed energy system are unrealistic and fail to address myriad real-world considerations that render his proposal infeasible.

As a result of my analysis, I take exception to the overriding conclusions from the Expert Report of Mark Z. Jacobson, dated April 6, 2018, that state:

> "I conclude … that it is both technically and economically feasible to transition from a predominantly fossil fuel-based energy system to a 100% clean, renewable energy system for all energy sectors by 2050, with about 80% conversion by 2030…" (page 2)

and

> "Our research further finds that the U.S. electric power grid with 100% WWS can stay stable at low cost (similar or less than today's direct energy cost …" (page 4)

In my expert opinion, Mark Jacobson has failed to adequately support these statements because he:

- Relies on insufficient and/or flawed facts or data, including but not limited to the timeline for transition to a 100% WWS system, the amount of demand response available, the assumptions regarding dispatching and expanding hydropower, and the costs of UTES storage and long distance transmission lines.

- Does not use reliable methods for key aspects of his proposed solution, including but not limited to design and operation of a long distance transmission system, simulating a timeline for transitioning to a 100% WWS system, and supplying essential grid services like frequency control and operating reserves.

- Does not apply generally accepted principles and techniques reliably to support key components of his testimony, including but not limited to the values he uses for cost of capital, the method he uses for estimating total capital requirements, the lack of indexing for different year dollars in certain instances, the method he uses for determining capacity factors, and ignoring considering extreme conditions and macroeconomic affects in his analyses.

I end by reiterating the warning from Clack et al. (2017) (page 6722):

> "Policy makers should treat with caution any visions of a rapid, reliable, and low-cost transition to entire energy systems that relies almost exclusively on wind, solar, and hydroelectric power."

6. Information Relied Upon and Considered

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7. Compensation

My rate for expert services in this case is $350/hour.

I have not testified as an expert at trial or by deposition within the preceding four (4) years.

Appendix A: CV

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EDUCATION:

Feb 1975 B.S., Chemical Engineering, Massachusetts Institute of Technology

Honors:
- American Institute of Chemists' Student Award
- Phi Lambda Upsilon (Honorary Chemical Society)
- Tau Beta Pi (Honorary Engineering Society)

Feb 1975 M.S., Chemical Engineering Practice, Massachusetts Institute of Technology

June 1980 Chemical Engineer's Degree, Massachusetts Institute of Technology

PROFESSIONAL EXPERIENCE:

1989 - present Massachusetts Institute of Technology

Research Areas:
- Controlling CO_2 Emissions from Power Plants
- Greenhouse Gas Mitigation Technologies
- Geothermal Energy and Heat Mining
- Hazardous Waste Disposal and Environmental Remediation
- Industrial Energy Use and Analysis

1986 - 1988 Laser Analytics Division, Spectra-Physics, Inc.

1981 - 1986 Aspen Technology, Inc.

1980 - 1981 Massachusetts Institute of Technology Energy Laboratory - ASPEN Project

1975 - 1978 Stone & Webster Engineering Corp.

Summers 72,73,74 Eastman Kodak Company

PROFESSIONAL AND HONOR SOCIETIES:

American Institute of Chemical Engineers
EIT Certificate
Phi Lambda Upsilon
Tau Beta Pi

AWARDS:

Greenman Award (2010) from the International Energy Agency Greenhouse Gas R&D Programme "in recognition of contributions made to the development of greenhouse gas control technologies"

Certificate from the Intergovernmental Panel on Climate Change (IPCC) "for contributing to the award of the Nobel Peace Prize for 2007 to the IPCC"

CONSULTING (Partial list, 1989-present):

Alstom Power
Aspen Technology, Inc.
Air Products
BP
Cabot Corporation
Clean Air Task Force
Clean Harbors
Coal Utilization Research Council
Connecticut Center for Advanced Technology, Inc.
EPRI
European Commission
FutureGen Alliance
General Electric Company
ICF
Kværner Engineering
Mannesmann
Metalor USA Refining Corporation
Ministry of the Environment (Japan)
New Energy and Industrial Technology
Development Organization (Japan)
OECD Environmental Directorate
Praxair
Quantum Reservoir Impact
SES Innovation
Technology Centre Mongstad
Total
U.S. Department of Energy
VerTech Treatment Systems
World bank

Appendix B: Publications 2008-Present

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Appendix C: Assessment of Jacobson's Methods for Calculating Hydrogen Storage Costs

This appendix provides detail on Jacobson's methods for calculating the costs of his proposed hydrogen storage system. Jacobson has made significant changes to the cost calculations for this hydrogen storage system between Jacobson et al. (2015b) and Jacobson et al. (2018). This appendix reviews and comments on both sets of calculations.

Jacobson estimates hydrogen costs as 0.46 (0.22-0.69) cents per kilowatt-hour (¢/kWh), per Jacobson et al. (2015b).[38] These costs reflect 2013 year-dollars.[39]

According to Jacobson et al. (2015b), the basis for these hydrogen costs is an earlier publication by Jacobson: Jacobson MZ, Colella WG, Golden DM (2005) Cleaning the air and improving health with hydrogen fuel-cell vehicles. *Science* 308(5730):1901-1905, referred to in this appendix as Jacobson et al. (2005).[40]

This remainder of this appendix provides detail and calculations that highlight flaws and errors associated with the figures in Jacobson et al. (2005), Jacobson et al. (2015b), and Jacobson et al. (2018).

Issue #1 – The hydrogen cost figures in Jacobson et al. (2015b) do not match the figures in Jacobson et al. (2005) despite Jacobson's reference and appear to be underestimated.

Details for hydrogen generation costs are given in Jacobson et al. (2005), Supporting Online Material, Section 4, pages 22-23, Table S2. The hydrogen cost generation costs include four components:

1) Electrolyzer;
2) Compressor;
3) Storage equipment; and
4) Water costs.

Table S2 of Jacobson et al. (2005) reports costs for each of these components in both low and high cases in units of \$kgH_2 as indicated in Table C-1 below. The sum of these components, per the total row of Table C-1, yields \$1.40 to \$3.66.

[38] Jacobson et al. (2015b), Table 2, page 15063, row "H_2 prod/compress/stor. (excl. elec. Cost) (¢/kWh)". The kilowatt-hours (kWh) in this figure refer to all energy. This cost excludes electricity; electricity costs are considered elsewhere in Jacobson et al. (2015b), Table 2.

[39] Jacobson et al. (2015b), Table 2, page 15063 directly states that electricity costs presented therein are in "2013 dollars."

[40] Jacobson et al. (2015b), Table 2, page 15063, footnote m makes reference to citation (38), which is Jacobson et al. (2005) as indicated on page 15065 of Jacobson et al. (2015b).

Table C-1: Hydrogen Storage Costs from Jacobson et al. (2005)

Hydrogen Cost Component	Low Value	High Value	Source Row from Jacobson et al. (2005), Table S2
Electrolyzer	\$0.39	\$2.00	Cost of electrolysis for producing H_2 (\$/kg-H_2)
Compressor	\$0.70	\$1.34	Cost of H_2 compression (\$/kg-H_2)
Storage equipment	\$0.31	\$0.31	Cost of H_2 storage (\$/kg-H_2)
Water Costs	\$0.005	\$0.009	Cost of water per kg-H_2 (\$/kg-H_2)
Total	**\$1.40**	**\$3.66**	
Note: Where appropriate, figures rounded to two decimal places for consistency with figures reported in Jacobson et al. (2015b); Jacobson et al. (2005) provides figures to numerous decimal places on an inconsistent basis.			

The totals in Table C-1 do not match the values reports in Jacobson et al. (2015b), Table 2, page 15063, footnote m. This is summarized in Table C-2.

Table C-2: Comparison of Hydrogen Storage Costs from Jacobson et al. (2005) and Jacobson et al. (2015b)

Publication	Low Value	High Value	Source
Jacobson et al. (2005)	\$1.40	\$3.66	Table C-1, row "Total"
Jacobson et al. (2015b)	\$1.16	\$3.57	Jacobson et al (2015b), page 15063, footnote m.
Difference	-17.14%	-2.46%	Calculated as [2015b value – 2005 value] / [2005 value]

This expert report does not speculate on why there is a mismatch between these two sets of numbers. However, I note that there is a difference between the values cited by Jacobson et al. (2015b) in support of the figures used, and the values actually found in the citation. The extent of this difference is not consistent between the lower and higher values calculated across the two publications. Jacobson does not provide any explanation for this difference.

The effect of this flaw is to reduce the hydrogen storage costs estimated within Jacobson et al. (2015b), and therefore to understate the overall costs of Jacobson's proposed energy system.

Issue #2 – Jacobson fails to adjust his inputs on a dollar-year basis as appropriate and therefore underestimates hydrogen storage costs.

As stated above, the figures in Jacobson et al. (2015b) reflect 2013 year-dollars. However, Jacobson et al. (2005) was published in 2005; the year-dollar basis for the figures therein must be 2005 year-dollars or year-dollars from a year prior to 2005. There is no mention of dollar-year basis in Jacobson et al. (2005), Supporting Online Information, Table S2. However, Table 1 of Jacobson et al. (2005) indicates use of a 2004 year-dollar basis in this publication.[41]

Jacobson et al. (2015b) makes no mention of indexing to correct for dollar-year basis. While, as described in Issue #1, the figures between Jacobson et al. (2005) and Jacobson et al. (2015b) do not match, the discrepancy in Issue #1 cannot be explained by adjustments for dollar-year basis, because such adjustments between 2004 and 2013 would raise costs, and not lower them. However, the discrepancy noted in Issue #1 features lower costs for the 2013 year-dollar basis than for the 2004 year-dollar basis.

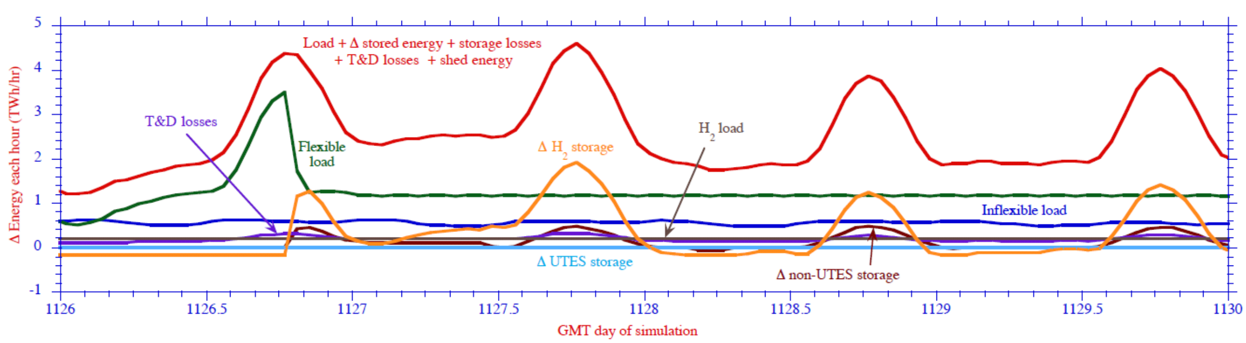
The Consumer Price Index rose by approximately 23 percent between 2004 and 2013.[42] By failing to account for inflation from the original year-dollar basis in which hydrogen storage costs were estimated in Jacobson et al. (2005), the figures in Jacobson et al. (2015b) therefore appear to substantially underestimate the costs of hydrogen storage.

Issue #3 – The capacity factors are inconsistent between Jacobson et al. (2005) and Jacobson et al. (2015b), resulting in an underestimation of costs.

To calculate electrolyzer costs, Jacobson et al. (2005) uses capacity factors, referred to as "fraction of time electrolyzer used."[43] These capacity factors are 95 percent for the "low value" case and 50 percent for the "high value" case.

However, this is in contradiction to the figures presented in Jacobson et al. (2015b). Specifically, the third panel of Figure S6 on page 19 of the Supporting Information to Jacobson et al. (2015b) is reproduced below as Figure C-1.

Figure C-1.



Source: Jacobson et al. (2015b), Supporting Information, Figure S6, third panel, page 19.

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[41] Jacobson et al. (2005), page 1904, Table 1 provides "Estimated health, climate, and total cost reductions (positive values) or increases (negative values) per year in 2004 dollars for each of the four cases discussed."
[42] U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index Research Series Using Current Methods (CPI-U-RS), U.S. city average, All items, not seasonally adjusted, December 1977 = 100, available online at: https://www.bls.gov/cpi/research-series/allitems.pdf. Per these data, the Consumer Price Index averaged 277.5 in 2004 and 342.5 in 2013, suggesting an increase of (342.5/277.5) – 1, or 23.42 percent.
[43] Jacobson et al. (2005), Supporting Online Information, Table 2, page 22-23, row "Fraction of time electrolyzer used." Footnote v to Table 2 reads: "the high estimate assumes that multiple connected wind farms reduce intermittency."

In this figure, the electrical load going to the hydrogen storage system is represented by the orange line. The load going to the hydrogen storage system is shown to be about 2 terawatt-hours per hour (TWh/hr), or 2,000 gigawatts (GW). In Jacobson et al. (2015b), page 15061, Table 1, the average load for the system is listed as 180.2 GW.[44]

Assuming a maximum load of 2,000 GW and an average load of 180.2 GW, the capacity factor is 180.2 divided by 2,000, or approximately nine percent.[45]

My calculations, shown in Table C-3 below, indicate that aligning the capacity factor estimates between the simulations in Jacobson et al. (2015b) and the estimation of hydrogen storage system costs in Jacobson et al. (2005) yields a range for hydrogen costs of $11.5-$18.8 per kg-H_2.

Table C-3: Calculation of Hydrogen Storage Costs Using Capacity Factor Derived from Jacobson et al. (2015b)

Parameter	Low Value	High Value	Calculation	Source
Capacity Factor	0.95*	0.5*	a	Jacobson et al. (2005), Table S2, Row c
Cost of electrolysis for producing H_2 (\$/kg-H_2)	0.387	2.00	b	Jacobson et al. (2005), Table S2, Row m
Electrolyzer cost, adjusted for 9% capacity factor	4.09	11.1	$c = b * \frac{a}{0.09}$	Calculated value
Cost of H_2 compression (\$/kg-H_2)	0.7*	1.34	d	Jacobson et al. (2005), Table S2, Row u
Compressor cost, adjusted for 9% capacity factor (\$/kg-H_2)	7.39	7.44	$e = d * \frac{a}{0.09}$	Calculated value
Cost increase from 9% capacity factor (\$/kg-H_2)	10.4	15.2	$f = (c - b) + (e - d)$	Calculated value
H_2 costs, Jacobson et al. (2015b) (\$/kg-H_2)	1.16	3.57	g	Jacobson et al., 2015b, Table 2, footnote m
H_2 costs with cost increase	11.5	18.8	$h = f + g$	Calculated value
Factor increase over Jacobson et al. (2015b) H_2 costs	10.0	5.26	$i = \frac{h}{g}$	Calculated value

Data from Jacobson et al. (2005) reflect Table S2, pages 22-23, in the Supporting Online Information. Calculations and figures shown to three significant digits places. Asterisks (*) denote figures provided by Jacobson et al. (2005) shown to fewer than three significant digits. Figures may not calculate due to rounding.

[44] Jacobson et al. (2015b), page 15061, Table 1, column "(6) 2050 load used for H_2 production and compression," row "All Sectors".

[45] When equipment is sized, it is generally oversized from a theoretical estimate to take into account uncertainty and other issues (e.g., equipment outages). Therefore, the actual capacity factor is likely to be less than nine percent given an increased maximum load.

As indicated in Table C-3, applying the capacity factor derived from the estimates in Jacobson et al. (2015b) yields a cost of \$11.5-\$18.8 per kg-H_2. This cost exceeds the estimates under high capacity factors from Jacobson et al. (2005) by a factor of 5.3 to a factor of 10. Therefore, based on a misaligned capacity factor, Jacobson's costs for hydrogen storage appear to be underestimated.

Issue #4 – Jacobson underestimates hydrogen storage system costs by omitting some types of projects costs.

As described in Section 4.5.2 of this expert report, Jacobson et al. (2015b) only considers costs for major pieces of equipment, and not for additional project costs, such as engineering services, contingencies, interest during construction, and so on. As a result, he underestimates hydrogen storage system costs.

Issue #5 – Jacobson substantially revises his hydrogen electrolyzer and compressor costs downward in Jacobson et al. (2018) relative to Jacobson et al. (2015b) with inadequate explanation.

Table C-4 compares the components comprising hydrogen cost in dollars per kg-H_2 between the estimates in Jacobson et al. (2005), which were brought forward to Jacobson (2015b), and Jacobson et al. (2018).

Table C-4: Comparison of Hydrogen Storage Costs (\$/kg-H_2) from Jacobson et al. (2005) and Jacobson et al. (2018), by Component

Component	**Jacobson et al. (2005)**	**Jacobson et al. (2018)**			**Source and Derivation**
		Case A	**Case B**	**Case C**	
Electrolyzer	\$1.19 (\$0.39-\$2.00)	\$0.56 (\$0.20-\$0.92)			2005: Table C-1 2018: SI, page 7
Compressor	\$1.02 (\$0.70-\$1.34)	\$0.37 (\$0.15-\$0.60)			2005: Table C-1 2018: SI, page 7
Storage	\$0.31	\$2.06	\$0.09	\$2.32	2005: Table C-1 2018: SI, page 7 (see note 1)
Water Costs	\$.007 (\$.005-\$.009)	\$.007 (\$.005-\$.009)			2005: Table C-1 2018: SI, page 7
Total	**\$2.36 (see note 2)**	**\$2.99**	**\$1.03**	**\$3.26**	Sum of above components

Totals may not sum due to rounding to two decimal places. Table C-1 refers to the table in this Appendix. "SI" refers to the Supporting Information to Jacobson et al. (2018). Jacobson et al. (2015b) does not provide a breakdown of hydrogen storage costs by component, this table uses the per-component costs as reported in Jacobson et al. (2005), which Jacobson et al. (2015b) cites as a reference with regard to hydrogen storage costs.
Additional notes:
1. The difference in storage costs for the cases in Jacobson et al. (2018) is due to assumptions regarding days of hydrogen storage required as shown in Jacobson et al (2018) Table S1, column j. These are 23 days (Case A), 1 day (Case B), and 26 days (Case C).
2. This is the cost used in Jacobson et al. (2015b). As described in Issue #1 of this appendix, the component costs do not add to this total cost.

As indicated in the first two rows of Table C-4, Jacobson et al. (2018) features a considerably lower range for compressor costs in dollars per kg-H2 than the range of costs used in Jacobson et al. (2005). While there is some overlap between the corresponding ranges in electrolyzer costs between the two publications, the range in Jacobson et al. (2018) generally reflects lower costs. Jacobson offers no explanation for the decrease in electrolyzer costs by 53% and compressor costs by 64% in the three years between the publications.[46]

The remaining issues in this Appendix, i.e., Issues #6, #7, and #8 pertain specifically to figures and calculations performed in Jacobson et al. (2018).

Issue #6 – Jacobson et al. (2018) repeats the same errors regarding capacity factor as Jacobson et al. (2015b), thereby underestimating hydrogen storage costs.

Jacobson et al. (2018) does not provide data that aligns to Table S6 of Jacobson et al. (2015b), which indicated a capacity factor of approximately nine percent. Therefore, it is unclear what the simulations in Jacobson et al. (2018) indicate regarding the appropriate capacity factor to use for estimating hydrogen storage costs. Jacobson et al. (2018) state in the SI on page 7 that they use a capacity factor range of 50-95%, the exact same range assumed in Jacobson et al. (2015b). In addition, Jacobson et al. (2018) gives no indication that it used the LOADMATCH output to inform what an appropriate capacity factor should be. If this was done, Jacobson would be able to specify a capacity factor for each of the three cases (see discussions in Section 4.5.3 and App C, Issue #3), instead of using a generic range. It is my expert opinion that if the LOADMATCH output were available for Jacobson et al. (2018), it would reveal a capacity factor much closer to the 9% from Jacobson et al. (2015b) than the generic 50-95% range.

Issue #7 – Jacobson et al. (2018) uses an unreasonably low cost of capital, underestimating hydrogen storage costs.

Through Jacobson et al. (2018), the cost of capital applied is between one percent and three percent.[47] As described in this expert report in Section 4.5.1, reasonable cost of capital rates range from 6.2 percent to 7.7 percent; the cost of capital used by Jacobson et al. (2018) is underestimated. Critically, in Jacobson et al. (2005), the cost of capital used was between six percent and eight percent. [48]

The higher the cost of capital, the more expensive the financing for the project. By understating the cost of capital, Jacobson et al. (2018) underestimates hydrogen storage costs.

Issue #8 – The cost estimates in Jacobson et al. (2018) do not include all relevant project costs for hydrogen storage, thereby underestimating costs.

Page 7 of the Supporting Information to Jacobson et al. (2018) indicates a capital cost of "1.2-1.3" applied to electrolyzer costs, compressor costs, and storage costs. As described in Section

[46] From Table C-4, (\$0.56-\$1.19)/\$1.19 = a 53% decrease in electrolyzer costs; (\$0.37-\$1.02)/\$1.02 = a 64% decrease in compressor costs.

[47] Jacobson et al. (2018), SI, Page 30, Table S9, footnote

[48] Jacobson et al. (2005), SI, Page 23, Table S2, row e "interest rate"

4.5.2 of this expert report, the typical range for capital costs for similar projects is 3 to 5, rather than 1.2 to 1.3.

Summary – Recalculation of Jacobson et al. (2018) hydrogen costs using realistic inputs.

This section recalculates the cost of hydrogen using realistic inputs for capacity factor, the cost of capital, and capital cost multipliers, as well as the combination of all three inputs. The effects of recalculation of Jacobson et al. (2018) Case A using these realistic inputs is shown below and reproduced fully in Attachment A to this Appendix, Tables C-A-1 through C-A-5.

- **Jacobson et al. (2018) Case A.** Cost of hydrogen = **\$2.99/kgH$_2$**, per Jacobson et al. (2018), Supporting Information, Page 7, sum of electrolyzer, compressor, storage, and water costs. See also the derivation in Table C-4. For clarity, this calculation is reproduced in Table C-A-1.

- **Adjustment: use of capacity factor of 9%.** Resulting cost of hydrogen = **\$8.08/kgH$_2$**, per Table C-A-2.

- **Adjustment: use of cost of capital of 6.2% to 7.7%.** Resulting cost of hydrogen = **\$4.70/kgH$_2$** per Table C-A-3.

- **Adjustment: use of capital cost multipliers of 3 to 5.** Resulting cost of hydrogen = **\$9.10/kgH$_2$** per Table C-A-4.

- **Adjustment: use of capacity factor of 9%, cost of capital of 6.2% to 7.7%, and capital cost multipliers of 3 to 5.** Resulting cost of hydrogen = **\$35.43/kgH$_2$** per Table C-A-5.

Table C-5 summarizes these resulting costs of hydrogen under the use of realistic inputs.

Table C-5: Comparison of Hydrogen Storage System Costs under Realistic Inputs

Scenario	Hydrogen Storage System Cost	Cost Increase Relative to Jacobson et al. (2018) Case A*
Jacobson et al. (2018) Case A	\$2.99/kgH$_2$	1.0
Capacity factor of 9%	\$8.08/kgH$_2$	2.7
Interest rate of 6.2% to 7.7%	\$4.70/kgH$_2$	1.6
Capital cost multipliers of 3 to 5	\$9.10/kgH$_2$	3.0
Use of all three realistic inputs above	\$35.43/kgH$_2$	11.8

* Reflects the hydrogen storage system cost in each row divided by the midpoint hydrogen cost in Jacobson et al. (2018) Case A, i.e., \$2.99/kgH$_2$. Hydrogen storage system costs reflect final estimates derived in Tables C-A-1 through C-A-5.

If the results of the above analysis, i.e., a cost increase in hydrogen storage system costs by a factor of 11.8 were relayed into Jacobson et al. (2018), Supporting Information, Table S9, page 28-29, column "North America," row "H$_2$ production/compression/storage," the value of 0.474 ¢/kWh would increase by a factor of 11.8 (i.e., 35.43/2.99) to 5.62 ¢/kWh. The corresponding Levelized Cost of Energy (LCOE) for all energy would rise by the difference between 5.62

¢/kWh and 0.474 ¢/kWh, or 5.15 ¢/kWh. Therefore, it would increase from 10.51 ¢/kWh, as listed in Jacobson et al. (2018), Supporting Information, Table S9, page 28-29, column "North America," row "Total LCOE (¢/kWh-all-energy)" to 15.66 ¢/kWh. Therefore, one can argue that the total energy costs in Jacobson et al. (2018) should be 49 percent greater (i.e., 5.15/10.51) than reported in Table S9 for North America, Case A solely as a result of unrealistic inputs in the calculation of costs for the hydrogen production, compression, and storage system.

Based on this analysis, I conclude that the hydrogen storage costs, and therefore the overall energy system costs found in Jacobson et al. (2015b) and Jacobson et al. (2018), and relied upon in his Expert Report, are substantially underestimated.

Appendix C

Attachment A: Derivation of Hydrogen Storage System Costs Consistent with Jacobson et al. (2018) Case A under Realistic Inputs

Table C-A-1: Derivation of Jacobson et al. (2018) Hydrogen Storage System Costs, with no Input Adjustments

Parameter	Low Value	High Value	Calculation	Source
Electrolyzer				
Capital cost ($/kw)	$300	$450	a	Jacobson et al. (2018), Supporting Information, page 7
Capacity factor	0.95	0.5	b	
Lifetime, years	15	10	c	
Interest rate	0.01	0.03	d	Jacobson et al. (2018), Supporting Information, page 30, Footnote to Table S9
Annual charge rate	0.072	0.117	$e = \frac{d*(1+d)^c}{(1+d)^c-1}$	Calculated value
Installation factor	1.2	1.3	f	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/kw/yr	26.0	68.6	$g = f * e * a$	Calculated value
Annual O&M cost factor	0.015	0.015	h	Jacobson et al. (2018), Supporting Information, page 7
O&M cost, $/kw/yr	4.50	6.75	$i = h * a$	Calculated value
Total cost, $/kw/yr	30.5	75.3	$j = g + i$	Calculated value
kWh/kg-H_2	53.37	53.37	k	Jacobson et al. (2018), Supporting Information, page 7
Hours/year	8,760	8,760	$l = 24 * 365$	Calculated value
Operating hours/year	8,322	4,380	$m = l * b$	Calculated value
Cost, $/kg-$H_2$	0.195	0.918	$n = j * \frac{k}{m}$	Calculated value
Average of low and high $/kg-$H_2$	0.557		o = Average of n_{low}, n_{high}	Calculated value

Parameter	Low Value	High Value	Calculation	Source
Compressor				
Capital cost ($)	400,000	515,000	p	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/yr	34,619	78,486	$q = f * e * p$	Calculated value
O&M cost, $/yr	6,000	7,725	$r = h * p$	Calculated value
Total annualized cost, $/yr	40,619	86,211	$s = q + r$	Calculated value
Compressor rate, kg-H_2/hr	33	33	t	Jacobson et al. (2018), Supporting Information, page 7
Cost, $/kg-$H_2$	0.148	0.596	$u = \frac{s}{(t*m)}$	Calculated value
Average of low and high $/kg-$H_2$	0.372		$v = Average\ of\ u_{low}, u_{high}$	Calculated value
Storage Equipment				
Capital cost ($/kg-$H_2$)	450	550	w	Jacobson et al. (2018), Supporting Information, page 7
Lifetime, years	50	30	x	
Annual charge rate	0.0255	0.0510	$y = \frac{d*(1+d)^x}{(1+d)^x-1}$	Calculated value
Annualized capital cost, $/kg-$H_2$/yr	13.8	36.5	$z = f * y * w$	Calculated value
O&M cost, $/kg-$H_2$/yr	6.75	8.25	$aa = h * w$	Calculated value
Total annualized cost, $/kg-$H_2$/yr	20.5	44.7	$ab = aa + z$	Calculated value
Days of hydrogen storage	23	23	ac	Jacobson et al. (2018), Supporting Information, Table S1
Cost, $/kg-$H_2$	1.29	2.82	$ad = ab * \frac{ac}{365}$	Calculated value to adjust cost for fraction of year that hydrogen is stored
Average of low and high $/kg-$H_2$	2.06		$ae = Average\ of\ ad_{low}, ad_{high}$	Calculated value
Cost summary, $/kg-$H_2$				
Electrolyzer	0.557		o	Matches numbers in Jacobson et al. (2018), Supporting Information, page 7
Compressor	0.372		v	
Storage	2.06		ae	
Water	0.00708		$af = \frac{0.00472+0.00944}{2}$	Jacobson et al. (2018), Supporting Information, page 7 (Electrolyzer paragraph)
Cost of H_2 storage system	**$2.99/kg-$H_2$**		$o + v + ae + af$	Calculated value
Note: Figures may not calculate due to rounding.				

Table C-A-2: Derivation of Jacobson et al. (2018) Hydrogen Storage System Costs, Adjusted for 9% Capacity Factor
Highlighted values reflect adjusted inputs

Parameter	Low Value	High Value	Calculation	Source
Electrolyzer				
Capital cost ($/kw)	$300	$450	a	Jacobson et al. (2018), Supporting Information, page 7
Capacity factor	0.09	0.09	b	Adjusted input, see discussion in Issues #3 and #6 of Appendix C
Lifetime, years	15	10	c	Jacobson et al. (2018), Supporting Information, page 7
Interest rate	0.01	0.03	d	Jacobson et al. (2018), Supporting Information, page 30, Footnote to Table S9
Annual charge rate	0.072	0.117	$e = \frac{d*(1+d)^c}{(1+d)^c-1}$	Calculated value
Installation factor	1.2	1.3	f	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/kw/yr	26.0	68.6	$g = f * e * a$	Calculated value
Annual O&M cost factor	0.015	0.015	h	Jacobson et al. (2018), Supporting Information, page 7
O&M cost, $/kw/yr	4.50	6.75	$i = h * a$	Calculated value
Total cost, $/kw/yr	30.5	75.3	$j = g + i$	Calculated value
kWh/kg-H_2	53.37	53.37	k	Jacobson et al. (2018), Supporting Information, page 7
Hours/year	8,760	8,760	$l = 24 * 365$	Calculated value
Operating hours/year	788	788	$m = l * b$	Calculated value
Cost, $/kg-$H_2$	2.06	5.10	$n = j * \frac{k}{m}$	Calculated value
Average of low and high $/kg-$H_2$	3.58		$o = Average\ of\ n_{low}, n_{high}$	Calculated value
Compressor				
Capital cost ($)	400,000	515,000	p	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/yr	34,619	78,486	$q = f * e * p$	Calculated value
O&M cost, $/yr	6,000	7,725	$r = h * p$	Calculated value
Total annualized cost, $/yr	40,619	86,211	$s = q + r$	Calculated value
Compressor rate, kg-H_2/hr	33	33	t	Jacobson et al. (2018), Supporting

Parameter	Low Value	High Value	Calculation	Source
				Information, page 7
Cost, $/kg-$H_2$	1.56	3.31	$u = \frac{s}{(t*m)}$	Calculated value
Average of low and high $/kg-$H_2$	2.44		$v = Average\ of\ u_{low}, u_{high}$	Calculated value
Storage Equipment				
Capital cost ($/kg-$H_2$)	450	550	w	Jacobson et al. (2018), Supporting Information, page 7
Lifetime, years	50	30	x	
Annual charge rate	0.0255	0.0510	$y = \frac{d*(1+d)^x}{(1+d)^x-1}$	Calculated value
Annualized capital cost, $/kg-$H_2$/yr	13.8	36.5	$z = f * y * w$	Calculated value
O&M cost, $/kg-$H_2$/yr	6.75	8.25	$aa = h * w$	Calculated value
Total annualized cost, $/kg-$H_2$/yr	20.5	44.7	$ab = aa + z$	Calculated value
Days of hydrogen storage	23	23	ac	Jacobson et al. (2018), Supporting Information, Table S1
Cost, $/kg-$H_2$	1.29	2.82	$ad = ab * \frac{ac}{365}$	Calculated value to adjust cost for fraction of year that hydrogen is stored
Average of low and high $/kg-$H_2$	2.06		$ae = Average\ of\ ad_{low}, ad_{high}$	Calculated value
Cost summary, $/kg-$H_2$				
Electrolyzer	3.58		o	See above
Compressor	2.44		v	See above
Storage	2.06		ae	See above
Water	0.00708		$af = \frac{0.00472+0.00944}{2}$	Jacobson et al. (2018), Supporting Information, page 7 (Electrolyzer paragraph)
Cost of H_2 storage system	**$8.08/kg-$H_2$**		$o + v + ae + af$	Calculated value
Note: Figures may not calculate due to rounding.				

Table C-A-3: Derivation of Jacobson et al. (2018) Hydrogen Storage System Costs, Adjusted for Cost of Capital of 6.2% to 7.7%
Highlighted values reflect adjusted inputs

Parameter	Low Value	High Value	Calculation	Source
Electrolyzer				
Capital cost ($/kw)	$300	$450	a	Jacobson et al. (2018), Supporting Information, page 7
Capacity factor	0.95	0.50	b	
Lifetime, years	15	10	c	
Interest rate	0.062	0.077	d	Adjusted input, see discussion in Issue #7 of Appendix C and Section 4.5.1 of this expert report
Annual charge rate	0.104	0.147	$e = \frac{d*(1+d)^c}{(1+d)^c-1}$	Calculated value
Installation factor	1.2	1.3	f	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/kw/yr	37.6	86.0	$g = f * e * a$	Calculated value
Annual O&M cost factor	0.015	0.015	h	Jacobson et al. (2018), Supporting Information, page 7
O&M cost, $/kw/yr	4.50	6.75	$i = h * a$	Calculated value
Total cost, $/kw/yr	42.1	92.8	$j = g + i$	Calculated value
kWh/kg-H_2	53.37	53.37	k	Jacobson et al. (2018), Supporting Information, page 7
Hours/year	8,760	8,760	$l = 24 * 365$	Calculated value
Operating hours/year	8,322	4,380	$m = l * b$	Calculated value
Cost, $/kg-$H_2$	0.270	1.13	$n = j * \frac{k}{m}$	Calculated value
Average of low and high $/kg-$H_2$	0.700		o = Average of n_{low}, n_{high}	Calculated value
Compressor				
Capital cost ($)	400,000	515,000	p	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/yr	50,070	98,429	$q = f * e * p$	Calculated value
O&M cost, $/yr	6,000	7,725	$r = h * p$	Calculated value
Total annualized cost, $/yr	56,070	106,154	$s = q + r$	Calculated value
Compressor rate, kg-H_2/hr	33	33	t	Jacobson et al. (2018), Supporting Information, page 7
Cost, $/kg-$H_2$	0.204	0.734	$u = \frac{s}{(t*m)}$	Calculated value

Parameter	Low Value	High Value	Calculation	Source
Average of low and high \$/kg-H_2	0.469		$v = Average\ of\ u_{low}, u_{high}$	Calculated value
Storage Equipment				
Capital cost (\$/kg-H_2)	450	550	w	Jacobson et al. (2018), Supporting Information, page 7
Lifetime, years	50	30	x	
Annual charge rate	0.0652	0.0863	$y = \frac{d*(1+d)^x}{(1+d)^x-1}$	Calculated value
Annualized capital cost, \$/kg-H_2/yr	35.2	61.7	$z = f * y * w$	Calculated value
O&M cost, \$/kg-H_2/yr	6.75	8.25	$aa = h * w$	Calculated value
Total annualized cost, \$/kg-H_2/yr	42.0	70.0	$ab = aa + z$	Calculated value
Days of hydrogen storage	23	23	ac	Jacobson et al. (2018), Supporting Information, Table S1
Cost, \$/kg-H_2	2.64	4.41	$ad = ab * \frac{ac}{365}$	Calculated value to adjust cost for fraction of year that hydrogen is stored
Average of low and high \$/kg-H_2	3.53		$ae = Average\ of\ ad_{low}, ad_{high}$	Calculated value
Cost summary, \$/kg-H_2				
Electrolyzer	0.700		o	See above
Compressor	0.469		v	See above
Storage	3.53		ae	See above
Water	0.00708		$af = \frac{0.00472+0.00944}{2}$	Jacobson et al. (2018), Supporting Information, page 7 (Electrolyzer paragraph)
Cost of H_2 storage system	**\$4.70/kg-H_2**		$o + v + ae + af$	Calculated value
Note: Figures may not calculate due to rounding.				

Table C-A-4: Derivation of Jacobson et al. (2018) Hydrogen Storage System Costs, Adjusted for Capital Cost Multipliers of 3 to 5
Highlighted values reflect adjusted inputs

Parameter	Low Value	High Value	Calculation	Source
Electrolyzer				
Capital cost ($/kw)	$300	$450	a	Jacobson et al. (2018), Supporting Information, page 7
Capacity factor	0.95	0.5	b	
Lifetime, years	15	10	c	
Interest rate	0.01	0.03	d	Jacobson et al. (2018), Supporting Information, page 30, Footnote to Table S9
Annual charge rate	0.072	0.117	$e = \frac{d*(1+d)^c}{(1+d)^c-1}$	Calculated value
Installation factor	3.0	5.0	f	Adjusted input, see discussion of Issue #8 in Appendix C and Section 4.5.2 of this expert report
Annualized capital cost, $/kw/yr	64.9	264	$g = f * e * a$	Calculated value
Annual O&M cost factor	0.015	0.015	h	Jacobson et al. (2018), Supporting Information, page 7
O&M cost, $/kw/yr	4.50	6.75	$i = h * a$	Calculated value
Total cost, $/kw/yr	69.4	271	$j = g + i$	Calculated value
kWh/kg-H_2	53.37	53.37	k	Jacobson et al. (2018), Supporting Information, page 7
Hours/year	8,760	8,760	$l = 24 * 365$	Calculated value
Operating hours/year	8,322	4,380	$m = l * b$	Calculated value
Cost, $/kg-$H_2$	0.445	3.30	$n = j * \frac{k}{m}$	Calculated value
Average of low and high $/kg-$H_2$	1.87		$o = Average\ of\ n_{low}, n_{high}$	Calculated value
Compressor				
Capital cost ($)	400,000	515,000	p	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/yr	86,549	301,869	$q = f * e * p$	Calculated value
O&M cost, $/yr	6,000	7,725	$r = h * p$	Calculated value
Total annualized cost, $/yr	92,549	309,594	$s = q + r$	Calculated value
Compressor rate, kg-H_2/hr	33	33	t	Jacobson et al. (2018), Supporting Information, page 7

Parameter	Low Value	High Value	Calculation	Source
Cost, \$/kg-H_2	0.337	2.14	$u = \frac{s}{(t*m)}$	Calculated value
Average of low and high \$/kg-H_2	1.24		$v = Average\ of\ u_{low}, u_{high}$	Calculated value
Storage Equipment				
Capital cost (\$/kg-H_2)	450	550	w	Jacobson et al. (2018), Supporting Information, page 7
Lifetime, years	50	30	x	
Annual charge rate	0.0255	0.0510	$y = \frac{d*(1+d)^x}{(1+d)^x-1}$	Calculated value
Annualized capital cost, \$/kg-H_2/yr	34.4	140	$z = f * y * w$	Calculated value
O&M cost, \$/kg-H_2/yr	6.75	8.25	$aa = h * w$	Calculated value
Total annualized cost, \$/kg-H_2/yr	41.2	149	$ab = aa + z$	Calculated value
Days of hydrogen storage	23	23	ac	Jacobson et al. (2018), Supporting Information, Table S1
Cost, \$/kg-H_2	2.60	9.36	$ad = ab * \frac{ac}{365}$	Calculated value to adjust cost for fraction of year that hydrogen is stored
Average of low and high \$/kg-H_2	5.98		$ae = Average\ of\ ad_{low}, ad_{high}$	Calculated value
Cost summary, \$/kg-H_2				
Electrolyzer	1.87		o	See above
Compressor	1.24		v	See above
Storage	5.98		ae	See above
Water	0.00708		$af = \frac{0.00472+0.00944}{2}$	Jacobson et al. (2018), Supporting Information, page 7 (Electrolyzer paragraph)
Cost of H_2 storage system	**\$9.10/kg-H_2**		$o + v + ae + af$	Calculated value
Note: Figures may not calculate due to rounding.				

Table C-A-5: Derivation of Jacobson et al. (2018) Hydrogen Storage System Costs, Adjusted for Capacity Factor of 9%, Cost of Capital of 6.2% to 7.7%, and Capital Cost Multipliers of 3 to 5
Highlighted values reflect adjusted inputs

Parameter	Low Value	High Value	Calculation	Source
Electrolyzer				
Capital cost ($/kw)	$300	$450	a	Jacobson et al. (2018), Supporting Information, page 7
Capacity factor	0.09	0.09	b	Adjusted input, see discussion in Issues #3 and #6 of Appendix C
Lifetime, years	15	10	c	Jacobson et al. (2018), Supporting Information, page 7
Interest rate	0.062	0.077	d	Adjusted input, see discussion in Issue #7 of Appendix C and Section 4.5.1 of this expert report
Annual charge rate	0.104	0.147	$e = \frac{d*(1+d)^c}{(1+d)^c-1}$	Calculated value
Installation factor	3.0	5.0	f	Adjusted input, see discussion of Issue #8 in Appendix C and Section 4.5.2 of this expert report
Annualized capital cost, $/kw/yr	93.9	331	$g = f * e * a$	Calculated value
Annual O&M cost factor	0.015	0.015	h	Jacobson et al. (2018), Supporting Information, page 7
O&M cost, $/kw/yr	4.50	6.75	$i = h * a$	Calculated value
Total cost, $/kw/yr	98.4	338	$j = g + i$	Calculated value
kWh/kg-H_2	53.37	53.37	k	Jacobson et al. (2018), Supporting Information, page 7
Hours/year	8,760	8,760	$l = 24 * 365$	Calculated value
Operating hours/year	788	788	$m = l * b$	Calculated value
Cost, $/kg-$H_2$	6.66	22.85	$n = j * \frac{k}{m}$	Calculated value
Average of low and high $/kg-$H_2$	14.75		o = Average of n_{low}, n_{high}	Calculated value

Parameter	Low Value	High Value	Calculation	Source
Compressor				
Capital cost ($)	400,000	515,000	p	Jacobson et al. (2018), Supporting Information, page 7
Annualized capital cost, $/yr	125,175	378,574	$q = f * e * p$	Calculated value
O&M cost, $/yr	6,000	7,725	$r = h * p$	Calculated value
Total annualized cost, $/yr	131,175	386,299	$s = q + r$	Calculated value
Compressor rate, kg-H_2/hr	33	33	t	Jacobson et al. (2018), Supporting Information, page 7
Cost, $/kg-$H_2$	5.04	14.85	$u = \frac{s}{(t * m)}$	Calculated value
Average of low and high $/kg-$H_2$	9.94		v = *Average of* u_{low}, u_{high}	Calculated value
Storage Equipment				
Capital cost ($/kg-$H_2$)	450	550	w	Jacobson et al. (2018), Supporting Information, page 7
Lifetime, years	50	30	x	
Annual charge rate	0.0652	0.0863	$y = \frac{d*(1+d)^x}{(1+d)^x - 1}$	Calculated value
Annualized capital cost, $/kg-$H_2$/yr	88.1	237	$z = f * y * w$	Calculated value
O&M cost, $/kg-$H_2$/yr	6.75	8.25	$aa = h * w$	Calculated value
Total annualized cost, $/kg-$H_2$/yr	94.8	246	$ab = aa + z$	Calculated value
Days of hydrogen storage	23	23	ac	Jacobson et al. (2018), Supporting Information, Table S1
Cost, $/kg-$H_2$	5.97	15.48	$ad = ab * \frac{ac}{365}$	Calculated value to adjust cost for fraction of year that hydrogen is stored
Average of low and high $/kg-$H_2$	10.73		ae = *Average of* ad_{low}, ad_{high}	Calculated value
Cost summary, $kg-$H_2$				
Electrolyzer	14.75		o	See above
Compressor	9.94		v	See above
Storage	10.73		ae	See above
Water	0.00708		$af = \frac{0.00472+0.00944}{2}$	Jacobson et al. (2018), Supporting Information, page 7 (Electrolyzer paragraph)
Cost of H_2 storage system	**$35.43/kg-$H_2$**		$o + v + ae + af$	Calculated value
Note: Figures may not calculate due to rounding.				

Appendix D: Assessment of Jacobson's Methods for Calculating Underground Thermal Energy Storage (UTES) Costs

This appendix provides detail on Jacobson's methods for calculating the costs of underground thermal energy storage (UTES) to be used as a component of his proposed 100% WWS energy system.

Issue #1 – Jacobson does not adequately document the sources for his UTES capital costs.

Jacobson et al. (2015b), Supplementary Information, Table S1, indicates capital costs for UTES at \$0.90/maximum-deliverable-kWh_{th}, with a broader range of \$0.071-\$1.71/maximum-deliverable-kWh_{th}.[49] Footnote 5 to Table S1 cites this figure to references (39) and (30), which are Gaine and Duffy (2010)[50] and Rehau (2011),[51] respectively, per page 27 of the Supplementary Information to Jacobson et al. (2015b).

My review of these two sources indicates that neither source contains capital costs nor do they suggest values for capital costs for UTES. Jacobson's UTES capital costs are therefore lacking in valid sourcing.

Issue #2 – Jacobson substantially underestimate UTES capital costs.

The lack of valid sourcing indicated in Issue #1 notwithstanding, the capital costs used in Jacobson et al. (2015b) for UTES are underestimated. Combining the capital cost estimate of \$0.90 (\$0.071-\$1.71)/maximum-deliverable-kWh_{th} with the energy storage capacity of 514.6 TWh in the same table yields a total capital cost investment figure of \$463 billion, with a range of \$37 billion to \$880 billion.[52]

Clack (2017) notes with regard to UTES capital costs: "the known capital costs for the Drake Landing system suggest a UTES installation cost of at least \$1.8 trillion for [Jacobson's proposed] 100% wind, solar and hydroelectric power system."[53] Clack's estimate of \$1.8 trillion,

[49] Specifically, these figures are located in Jacobson et al. (2015b), Supplementary Information, Table S1, column "Capital cost of storage beyond power generation (\$/maximum-deliverable-kWh-th)," row "UTES."

[50] Gaine K, Duffy A (2010) A life cycle cost analysis of large-scale thermal energy storage for buildings using combined heat and power. *Zero Emission Buildings Conference Proceedings*, eds Haase M, Andresen I, Hestnes A (Trondheim, Norway), 7-8 June 2010.

[51] Rehau (2011) Underground thermal energy storage. Available at http://www.igshpa.okstate.edu/membership/members_only/proceedings/2011/100611-1030-BChristopher%20Fox%20-%20Rehau%20-%20Underground%20Thermal%20Energy%20Storage.pdf. Accessed December 27, 2014.

[52] Jacobson et al. (2015b), Supplementary Information, Table S1, row "UTES," column "Capital cost of storage beyond power generation (\$/maximum-deliverable-kWh-th)," yields the \$0.90 (\$0.071-\$1.71) estimate; column "Assumed energy storage capacity (maximum-deliverable TWh)" yields the 514.6 estimate. 514.6 x \$0.90 = \$463 billion; 514.6 x \$0.071 = \$38 billion, 514.6 x \$1.71 = \$880 billion. There are 1 billion kilowatts in a terawatt, therefore multiplying the figure in dollars per kilowatt-hour by the figure in terawatt hours translates the dollar figure into the billions.

[53] Clack CTM, et al. (2017) Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar. Proc Natl Acad Sci USA 114:6722–6727, page 6727. Clack indicates that the Drake's Landing system's costs

based on the same project which Jacobson references as a demonstration of UTES storage, is nearly four times as high as Jacobson's central estimate of $463 billion, and more than double the high end of Jacobson's estimated range of $880 billion. This analysis shows that Jacobson's estimates for UTES capital costs are underestimated.

Issue #3 – Jacobson understates UTES capital costs by using an unrealistically low cost of capital.

As discussed in Section 4.5.1 of this expert report, Jacobson relies on the use of very low, unrealistic cost of capital rates. Jacobson et al. (2015b), Table 2, page 15063, row "All storage except H2 (¢/kWh)" reports energy costs of 0.33 (0.062-0.75) for all energy storage but hydrogen. Of this 0.33 central estimate, 0.22 ¢/kWh is for UTES.[54]

Using the UTES capital cost of $463 billion (see Issue #2) and cost of capital used in the calculus is a more realistic weighted average cost of capital (WACC) from Lazard (2017) of 7.7% under a 20-year economic lifetime,[55] the corresponding UTES cost is 0.39 ¢/kWh, rather than the 0.22 ¢/kWh estimated in Jacobson et al. (2015b), as indicated in Table D-A-2 of the Attachment to this Appendix.

Issue #4 – Jacobson does not acknowledge that retrofit costs for UTES systems will be substantially higher compared to "greenfield" situations such as Drake's Landing.

Drake's Landing comprised a new build project. However, most places where UTES will be applied in Jacobson's proposed energy systems will require retrofitting. It is generally accepted that retrofit projects of this nature are usually more expensive than new build or "greenfield" projects.

Summary – Recalculation of Jacobson's UTES costs using realistic inputs.

Starting with a UTES capital cost of $1.8 trillion (see Issue #2) and WACC of 7.7% with a 20 year economic lifetime (see Issue #3), the corresponding UTES cost is 1.50¢/kWh, rather than the 0.22 ¢/kWh estimated in Jacobson et al. (2015b), as indicated in Table D-A-3 of the Attachment to this Appendix.

Presently, Jacobson et al. (2015b), Table 2, page 15063, row "2050 total LCOE (¢/kWh-to-load) in 2013 dollars" indicates a central estimate cost of 11.37 ¢/kWh. Under the scenario with adjusted, realistic capital cost and cost of capital, the central estimate cost for 2050 total LCOE would instead be 12.65 ¢/kWh, or 11.37 plus the difference between 1.50 ¢/kWh and 0.22 ¢/kWh, or 1.28 ¢/kWh. This reflects an increase in total energy costs of over 11 percent, i.e., 12.65 / 11. 37 = 1.113.

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imply a cost of $3.5 billion (2015$) per TWh. $3.5 billion multiplied 514.6 TWh of UTES storage as estimated in Table S1 of Jacobson et al. (2015b) yields approximately $1.8 trillion, as estimated by Clack here.

[54] A detailed derivation is available in Attachment A to Appendix D, Table D-A-1.

[55] Lazard, "Lazard's Levelized Cost of Energy Analysis - Version 11.0" (2017), page 14. Available at https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

Therefore, based solely on Jacobson's unrealistic and unsubstantiated inputs for UTES capital costs, the costs of Jacobson's entire 100% WWS energy system appear to be understated by over 11 percent.

Appendix D

Attachment A: Derivation of Energy Costs with Realistic Inputs for UTES

Table D-A-1: Derivation of Jacobson et al. (2015b) "All storage except H_2" Costs, Consistent with Jacobson et al. (2015b) Table 2

Parameter	Low Value	Mid Value	High Value	Calculation	Source
Capital cost of storage beyond power generation ($/maximum deliverable-$kWh_{th}$)					
PHS	12	14	16	a	Jacobson et al. (2015b), Supporting Information, Table S1
STES	0.13	6.5	12.9	b	
PCM-ice	12.9	36.7	64.5	c	
PCM-CSP	10	15.3	20	d	
UTES	0.071	0.90	1.71	e	
Assumed energy storage capacity (maximum deliverable TWh)					
PHS		0.808		f	Jacobson et al. (2015b), Supporting Information, Table S1
STES		0.590		g	
PCM-ice		0.253		h	
PCM-CSP		13.26		i	
UTES		514.6		j	
Total capital cost ($ billions)					
PHS	9.7	11.3	12.9	$k = a * f$	Calculated values
STES	0.1	3.8	7.6	$l = b * g$	
PCM-ice	3.3	9.3	16.3	$m = c * h$	
PCM-CSP	132.6	202.9	265.2	$n = d * i$	
UTES	36.5	463.1	880.0	$o = e * j$	
Total Capital Cost	182.2	690.5	1,182.0	$p = k + l + m + n + o$	
Interest Rate	0.015	0.03	0.045	q	Jacobson et al. (2015b), Table 2, note j
Lifetime	35	30	25	r	
Annual Charge Rate	0.037	0.051	0.067	$s = \frac{q*(1+q)^r}{(1+q)^r - 1}$	Calculated value
Annual Capital Cost, Total	6.73	35.23	79.71	$t = s * p$	
Annual O&M Cost Factor	0.01	0.015	0.02	u	Jacobson et al. (2015a), Supporting Information, Table S11

Parameter	Low Value	Mid Value	High Value	Calculation	Source
Annual O&M Cost, Total	1.82	10.36	23.64	$v = p * u$	Calculated value
Terrawatt-hours/year (TWh/yr)		13,783		$w = 86{,}295 / 6$	Jacobson et al. (2015b), Table 2, "Total load met over 6 y"
All storage except H_2 (¢/kWh)	**0.062**	**0.33**	**0.75**	$x = 100 * \frac{t+v}{w}$	**Matches Jacobson et al. (2015b), Table 2**
Annual Capital Cost, UTES only	1.35	23.63	59.34	$y = s * o$	Calculated values
Annual O&M Cost, UTES only	0.37	6.95	17.60	$z = u * o$	
Storage, UTES only (¢/kWh)	**0.012**	**0.22**	**0.56**	$aa = 100 * \frac{y+z}{w}$	
Note: Figures may not calculate due to rounding.					

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Table D-A-2: Derivation of Jacobson et al. (2015b) UTES Costs, Adjusted for 7.7% Cost of Capital and 20-Year Project Lifetime
Highlighted values reflect adjusted inputs

Parameter	Mid Value	Calculation	Source
Capital cost of storage beyond power generation ($/maximum deliverable-kWhth) – UTES only	0.9	a	Jacobson et al. (2015b), Supporting Information, Table S1
Assumed energy storage capacity (maximum deliverable TWh) – UTES only	514.6	b	Jacobson et al. (2015b), Supporting Information, Table S1
Total capital cost, $billions – UTES only	463.1	$c = a * b$	Calculated value
Interest Rate	0.077	d	Adjusted inputs, see Issue #3 of Appendix D
Lifetime	20	e	
Annual Charge Rate	0.100	$f = \frac{d*(1+d)^e}{(1+d)^e-1}$	Calculated value
Annual O&M Cost Factor	0.015	g	Table D-A-1, row u
Terrawatt-hours/year (TWh/yr)	13,783	$h = 86{,}295 / 6$	Table D-A-1, row w
Annual Capital Cost, UTES only	46.1	$i = f * c$	Calculated values using adjusted inputs (calculations using Jacobson's inputs in Table D-A-1, rows y, z, aa)
Annual O&M Cost, UTES only	6.95	$j = g * c$	
Storage, UTES only (¢/kWh)	**0.39**	$k = 100* \frac{i+j}{h}$	
Note: Figures may not calculate due to rounding.			

Table D-A-3: Derivation of Jacobson et al. (2015b) UTES Costs, Adjusted for 7.7% Cost of Capital, 20-Year Project Lifetime, and $1.8 trillion capital cost
Highlighted values reflect adjusted inputs

Parameter	Mid Value	Calculation	Source
Total capital cost, $billions – UTES only	1,800	a	Adjusted input, see Issue #2 of Appendix D
Interest Rate	0.077	b	Adjusted inputs, see Issue #3 of Appendix D
Lifetime	20	c	
Annual Charge Rate	0.100	$d = \frac{b*(1+b)^c}{(1+b)^c-1}$	Calculated value
Annual O&M Cost Factor	0.015	e	Table D-A-1, row u
Terrawatt-hours/year (TWh/yr)	13,783	$f = 86{,}295 / 6$	Table D-A-1, row w
Annual Capital Cost, UTES only	179.3	$g = a * d$	Calculated values using adjusted inputs (calculations using Jacobson's inputs in Table D-A-1, rows y, z, aa)
Annual O&M Cost, UTES only	27.0	$h = a * e$	
Storage, UTES only (¢/kWh)	**1.50**	$i = 100 * \frac{g+h}{f}$	
Note: Figures may not calculate due to rounding.			

Appendix E: Assessment of Jacobson's Methods for Calculating Long-Distance Transmission Costs

This appendix provides detail on Jacobson's methods for calculating the costs of long-distance transmission required for his proposed 100% WWS energy system.

Jacobson et al. (2015b), Table 2, page 15063, footnote k indicates long-distance transmission costs of 1.2 (0.3-3.2) ¢/kWh. These costs are also used in Jacobson et al. (2018), as indicated on page 31 of the Supporting Information, footnote to Table S9. Per references in both Jacobson et al. (2015b) and Jacobson et al. (2018), these costs can be traced back to Delucchi MA, Jacobson MZ (2011) Providing all global energy with wind, water, and solar power, part II: Reliability, system and transmission costs, and policies. *Energy Policy* 39(3):1170–1190, (Delucchi and Jacobson, 2011), Table A.2a, page 1182, row "Total cost of extra transmission ($/kWh).

Issue #1 – Jacobson underestimates long-distance transmission costs by failing to correct for dollar-year basis.

Within Delucchi and Jacobson (2011), Table A.2a, page 1182, costs are clearly indicated as being on a 2007 year-dollar basis. These costs are imported as is into Jacobson et al. (2015b) and Jacobson et al. (2018) and represented as 2013 year-dollar basis. There is no correction for year-dollar basis. Best practices calls for indexing the different dollar year basis (see section 4.5.4). The Consumer Price Index rose by approximately 12 percent between 2007 and 2013.[56] By failing to index from the original year-dollar basis in which long-distance transmission costs were estimated in Jacobson et al. (2011), the figures in Jacobson et al. (2015b) underestimate the costs for long-distance transmission.

Issue #2 – The Delucchi and Jacobson (2011) calculations for long-distance transmission costs upon which Jacobson relies appear flawed and erroneous.

In Delucchi and Jacobson (2011), Table A.2a, page 1182, total transmission system capital costs are the sum of capital costs for two components:

1) Line, land, and tower – reflected in row "Capital cost of line, land, and tower ($/MW$_{rs}$) in Table A.2a. – $448,000 ($240,000-$680,000); and

2) Station equipment – reflected in row "Capital cost of station equipment ($/MW$_{rs}$) in Table A.2a. – $148,000 ($118,000-$177,000).

This sum is $596,000 (358,000-857,000) per megawatt. Costs per megawatt can be converted to dollars per kilowatt-hour by the following formula (Rubin et al., 2017, page 502):

[56] U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index Research Series Using Current Methods (CPI-U-RS), U.S. city average, All items, not seasonally adjusted, December 1977 = 100, available online at: https://www.bls.gov/cpi/research-series/allitems.pdf. Per these data, the Consumer Price Index averaged 304.6 in 2007 and 342.5 in 2013, suggesting an increase of (342.5/304.6) – 1, or 12.44 percent.

$$[Equation\ 1] \qquad \frac{Capital\ Cost\ (\$/MW) * Capital\ Charge\ Rate\ (\frac{fraction}{year})}{1000\frac{kW}{MW} * 8760\frac{hours}{year} * Capacity\ Factor}$$

In Equation 1, the capital charge rate is a function of the interest rate (or weighted average cost of capital) and project economic lifetime. It is calculated as shown in Equation 2, and can also be calculated using a spreadsheet's mortgage payment function.

$$[Equation\ 2] \qquad \frac{r * (1+r)^T}{(1+r)^T - 1}$$

where:

r is the interest rate
T the economic lifetime in years

In addition to the annualized capital cost, there are also costs associated with operations and maintenance (O&M) of the transmission system, which are given as a percentage of the capital costs. These O&M costs can also be converted to dollars per kilowatt-hour using Equation 3.

$$[Equation\ 3] \qquad \frac{Capital\ Cost\ (\$/MW) * Fraction\ of\ Capital\ Costs\ per\ year}{1000\frac{kW}{MW} * 8760\frac{hours}{year} * Capacity\ Factor}$$

Using the above equations, I calculate the cost of extra transmission using the discount rates, lifetimes, and maintenance costs listed in Table A.2a of Jacobson and Delucchi (2011) as follows:

- Low-end estimate: = **$0.005/kWh**

- Mid estimate: = **$0.014/kWh**

- High-end estimate: = **$0.0.029/kWh**

The derivations of each of these figures are provided in the Attachment to this appendix, Table E-A-1.

These results are not consistent with the results reported in Table A.2a of Jacobson and Delucchi (2011) of $0.012 (0.003-0.032)/kWh, which are then used in Jacobson et al. (2015b) and Jacobson et al. (2018). However, it appears that if the calculations erroneously 1) assume the capital charge rate is the same as the discount rate; and 2) ignore the O&M cost component, then it is possible to reproduce the low-end and mid estimate show in Jacobson and Delucchi (2011), Table A.2a, row "Total cost of extra transmission ($/kWh)," as follows:

- Mid estimate: $\frac{\$596{,}000*0.07}{1000*8760*0.4}$ = **$0.012/kWh**

- Low-end estimate: $\frac{\$358{,}000*0.03}{1000*8760*0.4}$ = **$0.003/kWh**

These derivations of each of these figures are provided in the Attachment to this appendix, Table E-A-2.

However, the same calculation does not yield an estimate commensurate with the value listed in Table A.2a:

- High-end estimate: $\frac{\$857{,}000\ *0.1}{1000*8760*0.4}$ = **$0.024/kWh** ≠ $0.032/kWh as listed in Table A.2a

From this analysis, as shown in the comparison between tables E-A-1 and E-A-2 in the Attachment to this Appendix, I conclude the following:

- First, there is an inconsistency, using whatever methods Delucchi and Jacobson (2011) applies, in calculating the high-end value for the extra cost of transmission versus the mid and low-end value. I cannot identify a reason for the inconsistency. The simplest explanation I can offer is that it is a calculation error.

- Second, it appears that Delucchi and Jacobson (2011) erroneously uses the discount rate in place of the capital charge rate. When doing this, I could replicate Jacobson's mid and low-end estimate.

- Third, it appears that Delucchi and Jacobson (2011) omits the annual maintenance cost from its calculation of the total cost of long-distance transmission.

Issue #3 – Comparison of Jacobson's long-distance transmission system capital costs to the capital costs of long-distance transmission projects currently in development further suggests that Jacobson substantially underestimates capital costs for long-distance transmission.

Jacobson and Delucchi (2011), Table A.2a reports capital costs as $372 ($299-$429)/MW-km in the row "Capital cost of transmission system (MW_{rs}$-km)." A note to Table A.2a indicates: "This quantity is calculated for comparison with estimates of total transmission-system capital costs in other studies," but does not list such studies.

Table E-1 provides a comparison of the capital costs for transmission systems in Jacobson and Delucchi (2011) to several long-distance transmission projects currently under development. The four projects in Table E-1 were chosen because their cost numbers have recently been publicly reported.

Table E-1: Comparison of Costs for Long-Distance Transmission Projects with Jacobson and Delucchi (2011) estimates

Project / Scenario	**Route**	**Cost ($ billions)**	**Length (miles)**	**Capacity (MW)**	**$/MW-km**	**Relative to 2011 Mid Estimate**	**Relative to 2011 High-End Estimate**
		a	*b*	*c*	$d = \frac{a}{\frac{b}{0.62} * c} * 10^9$	*e = d / $372*	*f = d / $429*
Jacobson and Delucchi (2011) Mid Estimate[a]	--	$3.0 (est.)	994	5,000	$372	1.0	0.9
Jacobson and Delucchi (2011) High-End Estimate[b]	--	$4.3 (est.)	1,243	5,000	$429	1.2	1.0
Northern Pass[c]	Quebec to NH	$1.6	192	1,090	$4,751	12.8	11.1
TransWest Express Transmission Project[d]	WY to CA	$3.0	730	3,000	$851	2.3	2.0
Plains & Eastern Clean Line[e]	OK to Southeast	$2.5	700	4,000	$555	1.5	1.3
Grain Belt Express Clean Line[f]	KS to NE	$2.3	780	4,000	$458	1.2	1.1

The factor of 0.62 in the formula for column d reflects the conversion of miles to kilometers using a factor of 0.62137119.
[a] Delucchi and Jacobson (2011), Table A.2a, page 1182. The cost is calculated using the capital cost of the transmission system of $372/MW-km. Miles are converted from kilometers, which are provided at 1,600.
[b] Delucchi and Jacobson (2011), Table A.2a, page 1182. The cost is calculated using the capital cost of the transmission system of $429/MW-km. Miles are converted from kilometers, which are provided at 2,000.
[c] http://www.northernpass.us/project-overview.htm; https://energy.gov/articles/department-energy-approves-presidential-permit-northern-pass-transmission-line-project
[d] How to get Wyoming wind to California", *Technology Review* **121** (2): 16-17 (2018).. Note that capacity for this project is "up to 3,000" and therefore costs presented are a lower-bound estimate. Costs could increase if ultimate capacity is lower than 3,000 MW.
[e] https://www.plainsandeasterncleanline.com/site/page/project-description
[f] https://www.grainbeltexpresscleanline.com/site/home

Each of these four projects features transmission system costs above the range featured in Delucchi and Jacobson (2011) and used in Jacobson et al. (2015b) and Jacobson et al. (2018) and therefore in his Expert Report. While these projects are of lower capacity and shorter distances, the differences in scale alone do not account for this discrepancy. The Northern Pass project is further along in its development and only needs a final permit – this project has seen cost escalations as the development process has progressed. Cost escalations have included concessions required for permission to site the lines, including agreements to bury large sections of lines. It is reasonable to expect similar cost escalations in the other projects as they move through their development processes. As a result, projects of this nature will feature final real costs that exceed their earlier, projected costs.

In summary, my conclusion from this exercise as reported in Table E-1 is that Jacobson substantially underestimates the capital cost of long-distance transmission lines.

Issue #4 – Jacobson makes assumptions on a highly-aggregated basis to determine the amount of long-distance transmission necessary, rather than relying on designs and modeling to explore his proposed long-distance transmission system.

Jacobson does not present any designs or simulations of his proposed long-distance transmission grid. At no point does he present even a conceptual design. He offers no commentary on how the long-distance transmission he proposes will interact with the existing grid structure that exists today, which is divided into three distinct interconnects with almost no electricity moving between them. Jacobson bases the amount of transmission necessary on two broad assumptions regarding distance (kilometers) and capacity (megawatts); at no point does he carry out any conceptual design or modeling to test any of his assumptions or determine whether his proposed system will suffer from congestion or other challenges.

Issue #5 – Jacobson uses an unsourced, unvalidated capacity factor for long-distance transmission which results in an underestimation of long-distance transmission costs.

In Delucchi and Jacobson (2011), Table A.2a, page 1182, the capacity factor of the transmission system is indicated to be 40 percent, per row "Average transmission current (fraction of current at rated capacity)." No explanation or justification is provided for this number.

In my opinion, this number is an overestimate: most of the energy supply in Jacobson's proposed 100% WWS system has low capacity factors. Specifically, in Jacobson et al. (2015b), Supplementary Information, Table S2, page 14, the proposed energy system includes a total of 5,780 gigawatts (5.78 TW) of wind and solar capacity.[57] Jacobson et al. (2015b), Table 2, page 15063, indicates total wind and solar generation of 13,900 TWh/yr.[58] This results in a system capacity of factor of 27.5 percent (i.e., 13,900 TWh/yr/(5.78 TW*8760hrs/yr) = 0.275).

In my opinion, transmission lines will not have a 40 percent capacity factor when the supply to those transmission lines is lower, at 27.5 percent. If the capacity factor of these lines is more realistic, at, for example, 20 percent in lieu of 40 percent, that alone would double the cost for long-distance transmission used by Jacobson.

[57] The 5,780 GW figure is the result of summing the values in the column, "Proposed existing plus new CONUS 2050 installed (GW)" for the first six rows, i.e., Onshore wind, Offshore wind, Residential PV, Commercial/government PV, Utility-scale PV, and CSP with some storage.

[58] This is calculated by adding the Total WWS supply before T&D losses of wind (43,509 TWh) and solar (39,901 TWh) and dividing by 6 years to get TWh/yr of wind and solar.

Appendix E

Attachment A: Analysis of Long-Distance Transmission Costs

Table E-A-1: Derivation of Long-Distance Transmission Costs based on Inputs and Parameters Provided in Delucchi and Jacobson (2011)

Parameter	Low Value	Mid Value	High Value	Calculation	Source
Capital cost of line, land, and tower ($/MW$_{TS}$)	240,000	448,000	680,000	a	Delucchi and Jacobson (2011), Table A.2a, page 1182
Capital cost of station equipment ($/MW$_{TS}$)	118,000	148,000	177,000	b	
Total capital cost ($/MW$_{TS}$)	358,000	596,000	857,000	$c = a + b$	Calculated value
Discount rate	0.03	0.07	0.10	d	Delucchi and Jacobson (2011), Table A.2a, page 1182
Project lifetime – lines and towers (years)	70	60	50	e	
Project lifetime – station equipment (years)	30	30	30	f	
Capital charge rate – lines and towers	0.034	0.071	0.101	$g = \frac{d*(1+d)^e}{(1+d)^e-1}$	Calculated value, see Equation 2 in Appendix E
Capital charge rate – station equipment	0.051	0.081	0.106	$h = \frac{d*(1+d)^f}{(1+d)^f-1}$	
Average transmission current (capacity factor)	0.4	0.4	0.4	i	Delucchi and Jacobson (2011), Table A.2a, page 1182
Hours/year (hrs/yr)	8,760	8,760	8,760	$j = 365 * 24$	Calculated value
Conversion for MW to kW	1,000	1,000	1,000	k	Conversion factor
Capital cost, for line, land, and tower ($/kWh)	0.0024	0.0091	0.0196	$l = \frac{a*g}{k*j*i}$	Calculated value, see Equation 1 in Appendix E
Capital cost, for station equipment ($/kWh)	0.0017	0.0034	0.0054	$m = \frac{b*g}{k*j*i}$	
Total capital cost ($/kWh)	0.0041	0.0125	0.0249	$n = l + m$	Calculated value; totals may not sum due to rounding
Maintenance cost (fraction of	0.010	0.010	0.015	o	Delucchi and Jacobson (2011),

Parameter	Low Value	Mid Value	High Value	Calculation	Source
capital cost per year)					Table A.2a, page 1182
Total maintenance cost ($/kWh)	0.0010	0.0017	0.0037	$p = \frac{c * o}{k * j * i}$	Calculated value, see Equation 3 in Appendix D
Total cost of extra transmission ($/kWh)	**0.005**	**0.014**	**0.029**	$q = p + n$	**Calculated value, see discussion in Issue #2 of Appendix D**
Note: Figures may not calculate due to rounding.					

Table E-A-2: Derivation of Long-Distance Transmission Costs as Described in Delucchi and Jacobson (2011) and used in Jacobson et al. (2015b) and Jacobson et al. (2018)

Parameter	Low Value	Mid Value	High Value	Calculation	Source
Capital cost of line, land, and tower ($\$/MW_{TS}$)	240,000	448,000	680,000	a	Delucchi and Jacobson (2011), Table A.2a, page 1182
Capital cost of station equipment ($\$/MW_{TS}$)	118,000	148,000	177,000	b	
Total capital cost ($\$/MW_{TS}$)	358,000	596,000	857,000	$c = a + b$	Calculated value
Discount rate	0.03	0.07	0.10	d	Delucchi and Jacobson (2011), Table A.2a, page 1182
Average transmission current (capacity factor)	0.4	0.4	0.4	e	Delucchi and Jacobson (2011), Table A.2a, page 1182
Hours/year (hrs/yr)	8,760	8,760	8,760	$f = 365 * 24$	Calculated value
Conversion for MW to kW	1,000	1,000	1,000	g	Conversion factor
Total cost of extra transmission ($/kWh)	**0.003**	**0.012**	**0.024**	$j = \frac{c * d}{e * f * g}$	**Calculated value, see Issue #2 of Appendix D**
Note: Figures may not calculate due to rounding.					