The Los Angeles 100% Renewable Energy Study

Los Angeles 100% Renewable Energy Study

Advisory Group Meeting #11

May 14, 21, 28, and June 4, 2020

Meeting Summary[1]

Meeting Notes Compiled by Kearns & West

Location

Virtual Meeting

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Virtual Session #1

Thursday, May 14, 2020, 10:00 a.m. to 12:00 p.m.

Virtual Session #1 Attendees

Advisory Group Members

Adam Lane, Los Angeles Business Council
Agustin Cabrera, RePowerLA
Allison Smith, Southern California Gas
Amanda Pantoja, Food & Water Watch
Andrea Rojas, Sierra Club
Armando Flores, Valley Industry Commerce Association
Austin Eriksson, California State University, Northridge
Ben Davis, California Solar Energy Industry Association
Bruce Tsuchida, The Brattle Group
Camden Collins, Office of Public Accountability (Ratepayer Advocate)
Carlos Baldenegro, Port of Los Angeles
Carter Atkins, Los Angeles World Airports
Clara Karger, Central City Association of Los Angeles

[1] This summary is provided as an overview of the meeting and is not meant as an official record or transcript of everything presented or discussed. The summary was prepared to the best of the ability of the note takers.

Los Angeles Department of Water & Power | NREL Transforming ENERGY

Dan Kegel, Neighborhood Council Sustainability Alliance
Danielle Mills, American Wind Energy Association California
Dominique Hargreaves, Office of the Mayor
Duane Muller, University of California, Los Angeles
Elaine Ulrich, U.S. Department of Energy Solar office
Frank Lopez, Southern California Gas
Fred Pickel, Office of Public Accountability (Ratepayer Advocate)
Jack Humphreville, DWP Advocacy Committee
Jasmin Vargas, Food & Water Watch
Jean-Cluade Claude Bertet, City of Los Angeles Attorney
Jillian Forte, Green Hydrogen Coalition
Jim Caldwell, Center for Energy Efficiency and Renewable Technologies
Jin Noh, California Energy Storage Alliance
Kendal Asuncion, Los Angeles Chamber of Commerce
Liz Anthony Gill, Center for Energy Efficiency and Renewable Technologies
Luis Amezcua, Sierra Club
Martin Marrufo, International Brotherhood of Electrical Workers - Local 18
Mathew Thomas, Los Angeles Unified School District
Matt Gregori, Southern California Gas
Matt Hale, Council District 2
Michael Christensen, Los Angeles World Airports
Nurit Katz, University of California, Los Angeles
Priscila Kasha, City of Los Angeles Attorney
Randy Krager, Southern California Public Power Authority
Sergio Duenas, California Energy Storage Alliance
Stuart Waldman, Valley Industry Commerce Association
Tony Wilkinson, Neighborhood Council
Virginia Cormier, International Brotherhood of Electrical Workers - Local 18

LADWP Staff

Amir Tabakh
Ashkan Nassiri
Carol Tucker
Danny Blustein
Dawn Cotterell
Greg Huynh
Jason Rondou
Jay Lim
John Gregory
Julie Liner
Julie Van Wagner
Leilani Johnson
Louis Ting
Paola Adler
Reiko Kerr
Robert Hodel
Scott Moon
Stephanie Spicer
Steve Swift

James Barner
Luis Jose Martinez
Nicholas J. Matiasz
Paul Schultz
Robert Hodel
Winifred Yancy

Project Team

David Keyser, National Renewable Energy Laboratory (NREL)
Doug Arent, NREL
Elaine Hale, NREL
Garvin Heath, NREL
Jaquelin Cochran, NREL
Meghan Mooney, NREL
Paul Denholm, NREL
Ramin Faramarzi, NREL
Scott Haase, NREL
Vikram Ravi, NREL
Alyson Scurlock, Kearns & West
Jack Hughes, Kearns & West
Joan Isaacson, Kearns & West

Observers

Ben Attai, City of Los Angeles
George Ban-Weiss, University of Southern California
Rory Stewart, Los Angeles Business Council
Yun Li, University of Southern California

Call to Order and Agenda Overview

Joan Isaacson, Advisory Group meeting facilitator from Kearns & West, welcomed all the virtual meeting attendees. She noted that this Advisory Group meeting was the first to be held on a virtual platform, made necessary by COVID-19 social distancing requirements. She explained that this was the first of four virtual meetings that will cover the topics scheduled for Advisory Group Meeting #11. She thanked the Advisory Group members for being patient as the project team determined how best to migrate the in-person meetings to an online platform.

Isaacson reviewed the agenda (see Appendix A), noting that documents relevant to the meeting had been posted on the LA100 website the day before, including the Scenario Matrix, Scenario and Technology Descriptions, Group Meeting Timeline, Detailed Modeling Framework, and the presentation slide deck used at this meeting. She explained that this meeting would focus on the final results for electricity demand projections and demand response. Joan also provided an overview of topics to be discussed at the next three virtual meetings. The May 21, 2020 meeting will focus on renewable options and trade-offs of moving from 90% to 100% renewable energy. The May 28, 2020 meeting will focus on local solar and storage, and the June 4, 2020 meeting the consist of a virtual Q&A follow-up for Advisory Group members.

Slides from all presentations are contained in Appendix B and are available on the LA100 website.

Welcome Remarks

Greg Huynh, LADWP Manager of the 100% Clean Energy Innovation Group, thanked the Advisory Group members for being flexible and accommodating. He noted that although COVID-19 has brought changes, LADWP is still committed to the collaborative Advisory Group process and the goal of achieving 100% renewable energy and that LA100 has not been delayed.

Jaquelin Cochran, NREL LA100 Principal Investigator, commented that she appreciated seeing the Advisory Group members. She noted that the virtual meeting style was meant to be open and encouraged the attendees to ask questions by typing in chat or by speaking. She welcomed any feedback to improve the virtual meetings.

Isaacson reviewed the Advisory Group's standing tips for productive discussions, followed by a brief orientation on webinar functions to ensure that all Advisory Group members understood the tools available for virtual participation.

LA100 Updates

Cochran gave an update on four additions to the LA100 study. The first addition is the inclusion of greenhouse gas emissions (GHG) changes resulting from non-power sector variables such as the electrification of buildings and light-duty vehicles. The second addition is changes in mortality from air quality. The third is monetizing morbidity, mortality, and GHG-related health benefits. The fourth is a qualitative description of impacts of electrifying medium- and heavy-duty vehicles. NREL explored adding electrification of medium- and heavy-duty vehicles to LA100 but this would have extended the study timeline. Instead, NREL is writing a qualitative description of electrification of medium- and heavy-duty vehicles, how they might be charged, and how electrification would affect study components such as distribution, bulk power, and air quality.

Major Themes from Advisory Group Member Questions and Discussion

- The addition of electrification of medium- and heavy-duty vehicles is appreciated. A question was raised about the effect of electrification on rates.
- Several comments addressed next week's webinar focus on getting from 90 to 100% renewable energy, including the importance of addressing considerations for getting to 90%.

Final Results: Electricity Demand Projections and Demand Response

Elaine Hale, Senior Research Engineer at NREL, gave a presentation on the final results for the electricity demand projections and demand response. Hale leads the load and demand response team for NREL. Hale explained that NREL is seeking feedback on further information and analysis they should provide for demand projections and demand response assumptions to help inform post-LA100 deliberations on policy.

Overview of Results (Moderate, High, High Stress Projections)

Hale reviewed electricity demand results for the Moderate, High, and High Stress projections, explaining that the three projections are used to test how different demand-side futures affect pathways to meet 100% renewable energy.

The Moderate projection represents the "low-hanging-fruit" of electrification and moderate improvements to energy efficiency and demand response. It represents significant change but falls short of the City of Los Angeles' 2019 Sustainable City pLAn (2019 pLAn) goals. The High projection aligns with most of 2019 pLAn electrification and efficiency goals and includes 80% light-duty vehicle electrification by 2045. The High Stress projection incorporates the most challenging load conditions by combining High electrification with low energy

efficiency improvements and demand response. Its purpose is to examine the most difficult load projection for the grid.

Hale overviewed what is and is not included in the results she would present. Electricity use measured at the customer meter for LADWP is included. Not included are distribution, sub-transmission, and transmission losses; non-LADWP balancing authority load (such as Glendale and Burbank); and changes in metered demand/retail sales due to behind-the-meter photovoltaics or battery energy storage. She also noted that demand response peak load reduction and energy shifting was excluded here but presented later in the presentation. Finally, she explained that to have a reliable power system, annual consumption must correlate with renewable energy availability. However, the peak electricity consumption value must also be met to have a reliable system. This peak statistic would be important in analyzing the results.

In terms of annual electricity consumption, in 2025 and 2030, building load in the High projection is lower than in the Moderate projection because greater energy efficiency is built into the High projection. The High projection has a higher annual consumption than the Moderate projection due to transportation electrification. The High Stress projection uses more energy overall because less energy efficiency is assumed.

For peak demand, there is growth all the way out to 2045. The peak tends to be in early August in afternoons due to building cooling load. The peak changes from 4 p.m. to 2 p.m. or 7 p.m., depending on where people are charging their cars. In the High Stress projection, charging at homes pushes the peak to 7 p.m. She also reviewed projected trends in annual demand by end use including the categories of transportation, commercial, residential, industrial, and other.

Major Themes from Advisory Group Member Questions and Discussion

- There was discussion about whether NREL plans to adjust economic forecasts to account for COVID-19 impacts.
- LADWP's actual sales could be incorporated into projections.
- Daily load shapes by season and shoulder months would be helpful.
- There were some questions about time-of-use impacts in the load projection assumptions.
- Can NREL provide the heating degree days and cooling degree days over time that reflect climate change assumptions?
- Why is there a sharp drop in cooling peak from 2040 to 2045? What are the technology assumptions?
- Why not plan for 100% renewable energy at Moderate demand level, and generate additional power with fossil fuels if other sectors become electrified?

Energy Efficiency

Hale continued on to discuss energy efficiency in the electricity projections. Greater energy efficiency is achieved by measures such as installing more efficient appliances and constructing buildings with tighter envelopes. This reduces the energy needed to meet the same level of service and will help reduce the overall cost. The Moderate, High and High Stress projections incorporate different assumptions about energy efficiency for residential buildings, commercial buildings, industrial premises, water systems, and transportation.

Major Themes from Advisory Group Member Questions and Discussion

- Where are demand response, electrification, and storage being deployed to make the model work?

Electrification

Hale explained that the Moderate, High and High Stress projections incorporate electrification of residential buildings, commercial buildings, industrial premises, water systems, and transportation. The High and High Stress projections incorporate the same electrification assumptions, but the Moderate projection assumes lower levels of electrification in the residential, commercial, light duty transportation, and industrial sectors.

Demand Response

Hale presented next on demand response. Demand response is any change in customer demand-side operations to match the available supply. NREL examined demand response programs from LADWP and included them in LA100. It was assumed that programs like the interruptible load program would become more automated over time. NREL also considered water system scheduling and residential and commercial end-use shifting, including two levels of electric vehicle charging profiles.

NREL examined the potential resources for demand response programs, said Hale, and she explained that participation rates were modeled using inputs such as incentive level, automation level, and level of marketing.

Major Themes from Advisory Group Member Questions and Discussion

- How did NREL calculate four hours a day of load shift in peak hour timing?
- The projections do not reflect the impact of residential solar installation rates, which are decreasing 2% per year.
- Have energy demands from moving reclaimed water uphill from Hyperion been considered?
- What would be the impact on demand response from the uptake of distributed solar generation of solar and storage?
- If the Reliability Pricing Model is not run again after accounting for demand response, it could lead to overbuild.
- Several cost questions were asked, including the cost savings from 10% peak demand savings, costs of transmission upgrades for renewables, and the relationship between capacity and storage costs.

Wrap-up and Next Steps

Isaacson thanked the attendees and said she looked forward to talking to them again at the next virtual meeting in a week.

Virtual Session #2

Thursday, May 21, 2020, 10:00 a.m. to 11:30 a.m.

Virtual Session #2 Attendees

Advisory Group Members

Adam Lane, Los Angeles Business Council
Allison Smith, Southern California Gas
Amanda Pantoja, Food & Water Action
Andrea Rojas, Sierra Club
Austin Eriksson, California State University, Northridge
Bonny Bentzin, University of California, Los Angeles (UCLA)
Bruce Tsuchida, The Brattle Group
Camden Collins, Office of Public Accountability (Ratepayer Advocate)
Carleigh Osen, CEERT
Carlos Baldenegro, Port of Los Angeles
Cris Liban, LA Metro
Christos Chrysillou, Los Angeles Unified School District
Duane Muller, UCLA
Evaristo Capalla, Valley Industry and Commerce Association
Frank Lopez, Southern California Gas
Jack Humphreville, DWP Advocacy Committee
Jasmin Vargas, Food &Water Action
Jean-Claude Bertet, City of Los Angeles Attorney
Jim Caldwell, Center for Energy Efficiency and Renewable Technologies
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Kendal Asuncion, Los Angeles Chamber of Commerce
Liz Anthony Gill, Center for Energy Efficiency and Renewable Technologies
Luis Amezcua, Sierra Club
Matthew Thomas, Los Angeles Unified School District
Nurit Katz, University of California, Los Angeles
Priscila Kasha, City of Los Angeles Attorney
Sarah Wiltfong, Los Angeles Business Federation
Sergio Duenas, California Energy Storage Alliance
Siva Gunda, California Energy Commission (CEC)
Terra Weeks, CEC
Tony Wilkinson, Neighborhood Council

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Jaquelin Cochran, NREL
Molly Hames, NREL
Paul Denholm, NREL
Ramin Faramarzi, NREL
Rachel Saxon, NREL
Vikram Ravi, NREL
Alyson Scurlock, Kearns & West
Joan Isaacson, Kearns & West
Taylor York, Kearns & West

Observers

Bill Engels, Water and Power Associates
Laura Nelson, Green Hydrogen Coalition
Lauren Harper, LACI
Rory Stewart, Los Angeles Business Council

Call to Order and Agenda Overview

Joan Isaacson, Advisory Group meeting facilitator from Kearns & West, welcomed all the virtual meeting attendees. She noted that this was the second of four virtual meetings that cover the topics scheduled for Advisory Group Meeting #11. She thanked the Advisory Group members for their continued patience and involvement in this virtual meeting format.

Isaacson reviewed the agenda (see Appendix A), noting that meeting documents have been posted on the LA100 website, including the presentation slides used during this session. She explained that this meeting would focus on renewable options and trade-offs to go from 90% to 100% renewable energy. Isaacson also provided an overview of topics to be discussed at the remaining two virtual meetings. The May 28, 2020 meeting will focus

on local solar and storage, and the June 4, 2020 meeting will consist of a virtual Q&A follow-up for Advisory Group members.

Slides from all presentations are available on the LA100 website.

Welcome Remarks

Greg Huynh, LADWP Manager of the 100% Clean Energy Innovation Group, thanked the Advisory Group members for being flexible and accommodating, noting that online engagement has been successful so far. Jaquelin Cochran, NREL LA100 Principal Investigator, expressed appreciation for Advisory Group member participation and noted that the team would like to ensure that all Advisory Group members are comfortable providing feedback via this virtual platform.

Isaacson reviewed the Advisory Group's standing tips for productive discussions, followed by a brief orientation on webinar functions to ensure that all Advisory Group members understood the tools available for virtual participation.

The Last Ten Percent: The Role of In-Basin Generation

Paul Denholm, Principal Energy Analyst at NREL, gave a presentation on considerations and options for addressing the last 10% of renewable energy. Denholm first provided an overview of how utilities have historically met peak capacity. He then discussed options for meeting peak capacity in systems with 100% renewable energy generation as well as tradeoffs for achieving the last 10% of renewable energy.

Denholm noted that the Initial Run results show sharp differences in costs across scenarios, attributed to costs associated with achieving the last 10%. Although the last 10% will be a long-term achievement, methods chosen to reach the first 90% will impact options for achieving the final 10%, especially considering once-though cooling units and other peaking capacity.

Planning for Peak Capacity

Denholm noted that the first 90% of renewable energy generation would likely be achieved through out-of-basin variable generation (wind and solar) and storage, other out-of-basin renewables such as geothermal and hydro, and in-basin solar with storage. He provided an example of demand patterns, illustrating the key challenges of meeting variations in demand. Addressing this variation has historically used three different types of generation: base load, intermediate load, and peaking.

Base load provides reliable and consistent generation, intermediate generation provides power to address variations in load, and peaking generation provides for the highest peaks in demand. Denholm noted that peaking plants generally represent only about 2% of generation, providing a significant amount of capacity that is rarely used. This results in very high costs for peak electricity, with more than one-third of customer bills coming from only 10% of energy use. More details on this concept can be found in the meeting presentation.

Denholm also presented considerations for enabling flexibility in the load, noting that the transition to 100% renewable energy provides an opportunity to utilize demand-side flexibility and could include behind-the-meter storage and electric vehicle charging. However, Denholm noted that activating demand-side flexibility will not accomplish reaching 100% renewable energy, such as on the hottest days, and supply-side solutions are needed as well.

Major Themes from Advisory Group Member Questions and Discussion

- Who would manage demand response – the utility, the customers, or a third party?

- Appreciation was expressed for the discussion about the cost and reasonableness of different generation sources. There is a lot of concern about the last 10% of generation and the cost of the 2% of power produced to address peaks. Fossil fuel should be considered be an option for this small percentage of generation.

Options to Provide Peak Capacity in 100% Renewable Energy Systems

Similar to fossil fuel generation, low utilization of renewable energy assets built to meet peak demand results in higher costs for each kilowatt hour of electricity. Renewable energy generation presents the added challenge of limited resources: Is generation available when needed? Denholm highlighted three supply-side challenges of a 100% renewable energy system: when not enough energy is available, when it cannot flow into the basin, when it cannot reach the right places in the basin.

Challenge: When not enough energy is available

On an ideal day, such as a sunny summer day, the system would have both enough renewable energy to meet demand during off-peak times and energy to charge storage to meet peak demand. However, during periods of extended demand on cloudy days or on days with little wind, either not enough power may be produced, or all power may be used with nothing remaining to charge storage.

For this reason, on some days, it is technically possible but economically difficult to achieve 100% renewable energy from wind, solar, and traditional storage. There will likely be only a few days with insufficient supply, but low utilization of peaking resources makes this power expensive. Transmission access is also a major consideration.

Challenge: When energy cannot flow into the basin

A 100% renewable energy system relies heavily on out-of-basin resources, leading to potential vulnerabilities in transmission. In many cases, transmission lines are already used to capacity. Additionally, if lines become damaged, the remaining lines could become overloaded and/or the system could experience disruptions. This may lead to a need for more transmission, or development of in-basin resources that can replace out-of-basin resources for a few days per year to avoid service disruptions.

Challenge: When energy cannot reach the right places in the basin

For the LADWP power system, transmission generally brings out-of-basin resources from the north and in-basin generation generally occurs in the south. Loads in the south generally rely on in-basin generation, creating challenges for a 100% renewable energy system that relies heavily on out-of-basin resources. Currently, in-basin transmission to bring energy from the north to the south is limited. As a result, any transmission line failures, or lines taken out of service for routine maintenance, would create a need for generation to meet loads in the south.

Major Themes from Advisory Group Member Questions and Discussion

- Is NREL including solar generation in Southern California or in the western region in the analysis?
- Does the analysis consider future energy efficiency measures? Demand response? Electrification?
- For days when peak capacity is not needed, can excess energy be sold? This could make up for the cost.
- Does “in-basin” include customer owned solar (residential, commercial) as well as LADWP owned solar?

What is the Ideal Solution for Addressing Peak Capacity?

Denholm highlighted solutions for peak capacity, including consideration of type and production of fuel, storing and delivering fuel, and converting fuel into electricity. The ideal solution for addressing challenges of peak

period capacity of 100% renewable energy is generation that is sited in-basin at diverse sites, can operate for extended periods of time (e.g., multi-day or longer), is renewable, and can use off-peak renewables to address seasonal mismatch.

Denholm noted that LA100 is not currently considering extended, multi-day demand response or solid biomass combustion (e.g., burning of trash, wood waste).

Denholm presented a solution framework consisting of three parts:

1. Producing a storable, renewably derived liquid or gaseous fuel
2. Storing and delivering this fuel
3. Converting this fuel into electricity

Pathways to Producing Storable Fuel

Denholm explained that creation of renewably derived, storable fuels could be accomplished either from biomass refined into fuel or from renewable electricity transformed into hydrogen using electrolysis. Biofuel pathways are available now and can be accomplished by either creating a refined, storable liquid fuel or digester biogas that can use existing pipelines. Denholm noted that this solution may work for Los Angeles, but supply challenges would create limits on widespread use of this method across California or the US. However, the creation of storable fuels would not use off-peak excess renewable energy.

Creating fuel with renewable electricity would involve using electricity to create hydrogen via electrolysis. He noted that hydrogen would then either be used directly in the shorter term or converted to some other more easily storable fuel for later use. Hydrogen does present challenges, as it must be transported and stored using specific types of infrastructure.

Storage and Delivery

Storage and delivery of fuel could be accomplished in gaseous or liquid form. Fuels in gaseous form may require underground storage, and hydrogen gas would require new pipeline infrastructure. Liquid fuels have multiple delivery and storage options and are superior to gasses in this sense.

Conversion of Fuels to Electricity

Conversion of renewably derived fuels back to electricity can occur by either combustion or non-combustion (fuel cell) pathways. The combustion pathway involves burning fuels in a combustion turbine, similar to a jet engine. These turbines produce NOx emissions but do not use water like a steam turbine does.

The non-combustion fuel cell pathway involves a battery-like device that uses hydrogen to produce electricity. These fuel cells have similar efficiency to a combustion turbine and do not use water. They also do not emit NOx. Denholm provided an overview of different types of fuel cells and a comparison to gas turbines.

Denholm noted that significant uncertainty exists in costs for renewable energy pathways, particularly for non-combustion options. Currently, fuel cells cost more than combustion turbines but this may change if large-scale production for vehicles occurs. The critical issue will be achieving cost reductions in fuel cell technology between now and when the last 10% of renewable energy is implemented. Large scale manufacturing of fuel cells can reduce costs but is not likely to occur before 2030.

Major Themes from Advisory Group Member Questions and Discussion

- Some do not consider biogas as a renewable resource. It is still a gas, generates emissions, and related storage facilities leak.
- Some expressed interest in the corrosive effects of hydrogen gas on existing infrastructure, and ways to minimize it by mixing hydrogen with natural gas.
- Appreciation for considering biofuels and hydrogen as cost-effective and flexible options was noted.
- Suggested discussion items, for future agendas before publication of the study report, include:
    - Reprise of investments on bulk systems to go from 30% to 90%
    - Reprise of transmission investments for both in-basin and imports into the basin
    - More information on options for the last 10% not discussed today, including consideration of hydrogen at Intermountain Power Plant and offshore wind with new transmission from the west
    - More discussion about how decisions made to achieve the first 90% affect options for the last 10% and vice-versa.
- Are there specific needs that hydrogen fuel cells can fulfill that turbines cannot? One example would be back-up power that currently uses diesel.
- Are fuel cells considered reliable? California State University, Northridge has had some issues operating fuel cells and has heard of similar reliability issues from others.
- Are other utilities in California using biofuels or considering their use?

Technology Eligibility by Scenario

Jaquelin Cochran, reviewed clarifications that have been made to the Scenario Matrix and asked Advisory Group members to provide feedback. She clarified that solid biomass is not allowed as a fuel in any scenario. She also explained that the NREL team is seeking guidance from the Advisory Group on how fuel created by renewable energy would be converted back to electricity. Cochran asked if it was the intent of the Advisory Group to allow for combustion pathways in the LA Leads, Emissions Free scenario. Currently, combustion from renewable energy-derived fuels is eligible in the SB100, High Distributed Energy Future, and Transmission Renaissance scenarios. Non-combustion is allowed in all scenarios. This is important because of cost implications since combustion options have lower cost.

Major Themes from Advisory Group Member Questions and Discussion

- A range of perspectives on combustion were shared:
    - Combustion options provide benefits as long as fuels are produced using only renewable energy.
    - If a fuel is to be created, LADWP should pursue a non-combustion route.
    - Including combustion in the LA Leads scenario may go against the original intent, creating too many similarities to other scenarios.
    - If energy production to address peak demand includes natural gas production, it may be unnecessary to convert energy to fuel and then back to energy when existing natural gas production could supply the fuel.
    - Environmental issues may arise from dependency on a methane-based solution that uses old technology.
- Examining the reliability and cost considerations for these different options is important.
- Should increasing battery storage be considered?
- Will all scenarios meet carbon neutrality?
- Can the proposed generic long-duration storage resource work for the multi-day events? Many storage technologies can operate for over 12 hours. Perhaps addressing the seasonal shift needs a hydrogen application, but multi-day issues can be resolved with other technologies.

- In-basin hydrogen may be needed but should be addressed on a case-by-case basis.
- Some AG members favored including lower cost options and using the model to assess carbon and NOx emissions.
- The California Energy Storage Alliance will provide comments on the inclusion of hydrogen combustion for LA Leads.

Wrap-up and Next Steps

Isaacson wrapped up by inviting Advisory Group members to provide further input on topics discussed at this session and reminded them to watch for posting of the slides before next week's virtual meeting.

Virtual Session #3

Thursday, May 28, 2020, 10:00 a.m. to 11:30 a.m.

Virtual Session #3 Attendees

Advisory Group Members

Adam Lane, Los Angeles Business Council
Allison Smith, Southern California Gas
Amanda Pantoja, Food & Water Action
Andrea Rojas, Sierra Club
Andy Shrader, Council District 5
Bonny Bentzin, University of California, Los Angeles (UCLA)
Bruce Tsuchida, The Brattle Group
Camden Collins, Office of Public Accountability (Ratepayer Advocate)
Carlos Baldenegro, Port of Los Angeles
Christos Chrysiliou, Los Angeles Unified School District
Dan Kegel, Neighborhood Council Sustainability Alliance
Dominique Hargreaves, Office of the Mayor
Duane Muller, UCLA
Elaine Ulrich, U.S. Department of Energy Solar office
Evaristo Capalla, Valley Industry and Commerce Association
Frank Lopez, Southern California Gas
Fred Pickel, Office of Public Accountability (Ratepayer Advocate)
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Jim Caldwell, Center for Energy Efficiency and Renewable Technologies
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Kendal Asuncion, Los Angeles Chamber of Commerce
Liz Anthony Gill, Center for Energy Efficiency and Renewable Technologies
Luis Amezcua, Sierra Club
Matt Hale, Council District 2
Mathew Thomas, Los Angeles Unified School District
Priscila Kasha, City of Los Angeles Attorney
Sarah Wiltfong, Los Angeles Business Federation
Sergio Duenas, California Energy Storage Alliance
Stuart Waldman, Valley Industry Commerce Association
Tony Wilkinson, Neighborhood Council

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Dawn Cotterell
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LeiLani Johnson
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Nicholas J. Matiasz
Paul Schultz
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Stephanie Spicer
Steve Swift

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Doug Arent, NREL
Garvin Heath, NREL
Jaquelin Cochran, NREL
Meghan Mooney, NREL
Paritosh Das, NREL
Ashreeta Prasanna, NREL
Paul Denholm, NREL
Ramin Faramarzi, NREL
Scott Haase, NREL
Alyson Scurlock, Kearns & West
Joan Isaacson, Kearns & West
Taylor York, Kearns & West
Emma Tome, Contractor

Observers

Bill Engels, Water and Power Associates
Rory Stewart, Los Angeles Business Council
Salem Afeworki, City of Costa Mesa

Call to Order and Agenda Overview

Joan Isaacson, Advisory Group meeting facilitator from Kearns & West, welcomed meeting participants. She noted that this was the third of four virtual sessions covering the topics scheduled for Advisory Group Meeting #11. She thanked the Advisory Group members for their continued patience and involvement in this virtual meeting format.

Isaacson reviewed the agenda (see Appendix A) and explained that this meeting would focus on local solar and storage distribution, with ample time reserved for questions and discussion.

Slides from all presentations are available on the LA100 website.

Welcome Remarks

Greg Huynh, LADWP Manager of the 100% Clean Energy Innovation Group, thanked Advisory Group members for their participation and noted that the virtual meetings have been going well. He highlighted the importance of continuing discussion with Advisory Group members and expressed hope that meetings would eventually return to an in-person format. He emphasized that Advisory Group member comments are welcome at any time.

Jaquelin Cochran, NREL LA100 Principal Investigator, then greeted the Advisory Group members. She noted that discussion about combustion generation from session two of this meeting series would continue during the question and answer session scheduled for June 4. She informed the group that Advisory Group Meeting #12 will also be held in a virtual format, with a multiple-session structure similar to this series. Cochran explained that the focus will be on cost, jobs, and reliability, and Advisory Group members will have a preview of draft final results. She encouraged Advisory Group members to provide input on the meeting format, including timing and duration of sessions.

Local Solar and Storage

Ben Sigrin, Senior Research Engineer at NREL, gave a presentation on outputs from local solar and storage modeling. He noted that "local solar" primarily refers to geographic distribution of solar generation within the LADWP service territory, including customer-adopted solar and LADWP-procured solar such as ground mounted and parking canopy mounted. He also noted that much of this study is the first of its kind in terms of scale and comprehensiveness. Modeling efforts have considered every household and business in the LADWP service territory, adding up to more than 600,000 unique agents.

Sigrin provided context for this analysis within the LA100 study, reviewed customer-owned rooftop solar and storage projections, and discussed identification and ranking of local solar sites within the LADWP service territory. This analysis is guided by several key questions: How much customer-owned distributed solar and storage could be adopted? Where? And what are the optimal sites for LADWP-procured solar? Results from this analysis will help determine what is built and where, as well as what portion of local resources are developed by LADWP.

Sigrin noted that this analysis is one of the final steps in understanding distributed generation and welcomed feedback from Advisory Group members on two important questions: What do you see as the most significant findings of this research, and what information and analysis can NREL provide to help inform post-LA100 deliberations on policy?

Customer-Owned Rooftop Solar Adoption

For customer-owned rooftop solar adoption modeling, Sigrin explained that the analysis incorporated five different scenarios, designed to compare moderate load, high load, and high stress cases. For energy compensation in high load cases, NREL's evaluation assumed net energy metering, while moderate load cases assumed net energy billing. He provided an overview of existing rooftop solar in Los Angeles, which includes approximately 365 megawatts adopted through 2018. The following themes emerged from the analysis:

- Household propensity to adopt solar is very strongly correlated with economic attractiveness – better payback leads to higher adoption rates.
- Peer effects are a strong theme – if one neighbor adopts solar others are more likely to do the same.
- Adoption rates are correlated with income.
- Low-density residential areas have a higher likelihood of adoption.

Framework for Projecting Adoption

Sigrin recapped the three steps for projecting local solar adoption: technical potential, or the technically feasible maximum amount of adoption; economic potential, or the amount of capacity that would be economical for the customer to adopt; and deployment, or the amount of technically and economically feasible system capacity likely to be adopted.

Technical Potential

The modeling shows that approximately 13.4 gigawatts of technical potential for rooftop solar and 3.3 gigawatts of potential for parking lot canopies exists within the LADWP service territory. Most of this potential is in the residential sector, followed by manufacturing and commercial, and nearly half is in census tracts that are designated as disadvantaged. Sigrin noted that rooftop suitability was not considered in this analysis due to data limitations. Previous research[2] using data from California's Single Family Affordable Solar Housing (SASH) program indicates about 10–19% of low-income buildings assessed were unsuitable for solar for non-shading issues, specifically: roof, excessive electrical upgrades, and other building code violations. Technical analysis considered system costs, with all incentives and rebates based on current statutes.

Economic Potential

Economic potential considers system cost and expected maintenance, retail bill savings from avoided electricity consumption, and eligibility for incentives, rebates, or avoided tax. For 2020, the NREL team assumed a cost of solar at $2,200 per kilowatt. As this cost declines over time, more capacity becomes economical, with most technical potential being economical by 2045. Analysis shows that by 2045 all technical potential would be saturated. Sigrin noted that when comparing moderate and high levels of electrification, electrification has only a modest impact on the capacity that is economical and ultimately deployed. Although loads are higher under high electrification scenarios, deployment is limited by the amount of roof space available.

Deployment

Modeling of solar deployment was calibrated using historic adoption data from the City of Los Angeles. Modeling shows deployment increasing over time, with between 2.8 and 3.8 gigawatts deployed by 2045, depending on adoption and electrification levels. Sigrin noted that high electrification increases deployment projections in the mid-term, but by 2045, deployment projections are similar under moderate and high electrification.

Major Themes from Advisory Group Member Questions and Discussion

- Does the study include technical potential for multi-family, and how does future multi-family housing growth impact the technical potential?
- Does the analysis consider system efficiency?
- Does economic analysis consider benefits to the utility from customer-built generation and storage, including avoided generation and capacity that would otherwise need to be addressed by the utility?
- Why is local solar being treated as an "objective" in this study? Utility-scale solar is much cheaper and easier to store and dispatch. This could be perceived as a social goal inside a business model.
- The meeting slides show an inflection point for deployment in 2025: What is the cause?
- Economic damage to families from the pandemic may be long term and may have an impact on customers' financial ability to adopt solar.

[2] https://www.nrel.gov/docs/fy18osti/70901.pdf, pg. 29

Multi-Family Building Subset Results

Sigrin focused on technical feasibility, economic feasibility, and deployment projections for multi-family residential buildings, noting that they compose a significant percentage of Los Angeles' building stock. Sigrin reported that local solar adoption has historically been focused in areas of single-family, owner-occupied homes. For multi-family residential buildings, NREL's analysis shows substantial technical potential — 2.06 gigawatts of rooftop and 0.34 gigawatts of on-site ground mounted. Sigrin noted that the feed-in tariff program may be useful for creating price signals and driving adoption of solar by multi-family residential building owners; however, as currently designed the program threshold excludes 76% of potential buildings. Most smaller buildings can offset at least 100% of annual consumption, while larger buildings could offset about 60%. Sigrin noted that results are averaged across the entire building stock, and therefore individual units likely vary.

Major Themes from Advisory Group Member Questions and Discussion

- Is local battery storage considered?
- Net metering has been the standard in California since 1995, set to be revisited once the solar share of the undiversified peak reached 5%. This has been passed by some California utilities, but maybe not by LADWP. LADWP is not regulated by these rules, but currently uses net metering. There are many details and differences in implementation.
- For net metering, should LADWP uptake energy during the day when its value is low and then release it at night when the price is high?
- Analysis of multi-family units by number of stories could be useful.

Customer-Owned Storage

When reporting on customer-owned distributed storage adoption, Sigrin began by explaining that adoption rates remain low in LADWP's service territory, with 10.8 megawatts adopted to date. Behind-the-meter storage could be a valuable resource if operated to minimize overall system costs and provide local system benefits. However, the value depends on how customers with storage will operate their systems. Sigrin also noted that customer perceived benefits do not always align with utility perceived benefits.

Instead of projecting customer-owned storage using the dGen model, NREL established an adoption forecast based on historic trends and adoption rates. Currently, about 10% of residential customers and 4% of non-residential customers who adopt solar also adopt storage. Using a linear trend, NREL projects that co-adoption of storage with solar will reach 100% by 2040 in the High Distributed Energy case.

Major Themes from Advisory Group Member Questions and Discussion

- Would LADWP subsidize batteries for customers trying to avoid buying power?
- Local generation is essential for a reliable grid. Although local solar is not at the same price point as remote generation, it is still necessary for a reliable grid.
- If rooftop solar is properly valued, storage will make economic sense and will justify increasing rates of storage adoption.
- How does the cost of behind-the-meter storage relate to the cost of utility storage in the Bulk Capacity Expansion Model?
- Efforts to increase energy efficiency and to use energy storage wisely, irrespective of the method, should be incorporated alongside efforts to achieve 100% renewable energy generation. Both should consider methods of keeping prices low and maintaining system reliability.
- In the dispatch model, does behind-the-meter storage behave in the same manner as utility-scale storage, and is there a valuation of customer benefits?

- Does analysis consider the impact of improvements and cost reduction of solar technologies, such as solar roof tiles and solar windows?

Identifying and Ranking Local Solar Sites

Next, Sigrin overviewed the methodology for determining optimal sites for LADWP-procured local solar. This assessment includes midsize, in-basin systems that have not yet been adopted, but that have been identified as part of the optimal resource portfolio by the Capacity Expansion Model. Using the RPM Capacity Expansion Model, NREL first determined local in-basin solar needs for each receiving station. Local solar was then allocated to individual sites based on a siting algorithm, and a simulation was conducted to determine distribution system impacts of local and rooftop solar. These results are then used to inform subsequent model runs and refine results.

Potential sites are screened and ranked based on a set of criteria that includes factors such as existing development, terrain, landmarks, etc. Cost-based variables are also applied, and sites are ranked by suitability. The result is a ranked list of about 30,000 possible sites to meet local solar targets. Results show 4.8 gigawatts of non-rooftop solar potential, with 1,897 megawatts of capacity for projects between one and 10 megawatts, and 707 megawatts of capacity for projects greater than 10 megawatts. Of this, about 61% of generation potential occurs in disadvantaged communities. Further, 3,851 megawatts could be deployed at a levelized cost of energy (LCOE) of less than $100 per megawatt hour based on 2020 costs. Carport and floating projects are ranked higher due to assumed zero land cost.

Major Themes from Advisory Group Member Questions and Discussion

- Do optimal LADWP local solar sites assume co-located storage?
- Are transportation easements included in local solar site analysis?
- The analysis should consider potential changes to technology over the next 25 years, which could increase solar potential.
- Regarding carports: Is the cost of real estate included in the siting analysis? It is likely that building and carport owners would charge rent for use of the space. What cost per watt increment was assumed for carport solar?
- Could methods such as real-time rates be utilized to prompt certain behaviors related to consumer storage?

Discussion Questions

Cochran sought input from Advisory Group members regarding the local storage research and next steps on policy member responses following in bullet points.

What do you see as the most significant findings of this research?

- The complexity of the modeling and the number of uncertainties, including with regard to local policy, is significant.
- How critical are behind-the-meter control issues to the assessment and to meeting overall energy demand, and what level of utilization is expected for these resources?

What information and analysis can NREL provide to help inform post-LA100 deliberations on policy?

- Heat maps, illustrating economic vs. technical potential for utility-owned solar, to help in determining where to site solar with respect to distribution station capacity.
- Multi-family residential potential broken down by number of stories, and maps showing deployment distribution.

Wrap-up and Next Steps

Isaacson wrapped up by inviting Advisory Group members to provide further email input to the team on topics discussed at this session and to attend the question and answer session scheduled for June 4.

Follow-Up Q&A Session

Thursday, June 4, 2020, 10:00 a.m. to 11:30 a.m.

Follow-Up Q&A Attendees

Advisory Group Members

Adam Lane, Los Angeles Business Council
Allison Smith, Southern California Gas
Andrea Rojas, Sierra Club
Andy Shrader, Council District 5
Austin Eriksson, California State University, Northridge
Bill Engels, Water and Power Associates
Bonny Bentzin, University of California, Los Angeles (UCLA)
Brissa Sotelo, Valero Wilmington Refinery
Bruce Tsuchida, The Brattle Group
Camden Collins, Office of Public Accountability (Ratepayer Advocate)
Carlos Baldenegro, Port of Los Angeles
Christos Chrysiliou, Los Angeles Unified School District
Dan Kegel, Neighborhood Council Sustainability Alliance
Duane Muller, UCLA
Elaine Ulrich, U.S. Department of Energy Solar office
Evaristo Capalla, Valley Industry and Commerce Association
Frank Lopez, Southern California Gas
Fred Pickel, Office of Accountability (Ratepayer Advocate)
Jack Humphreville, DWP Advocacy Committee
Jean-Claude Bertet, City of Los Angeles Attorney
Jim Caldwell, Center for Energy Efficiency and Renewable Technologies
Jin Noh, California Energy Storage Alliance
Laura Nelson, Green Hydrogen Coalition
Liz Anthony Gill, Center for Energy Efficiency and Renewable Technologies
Luis Amezcua, Sierra Club
Mathew Thomas, Los Angeles Unified School District
Michael Webster, Southern California Public Power Authority
Priscila Kasha, City of Los Angeles Attorney
Sarah Wiltfong, Los Angeles Business Federation
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Taylor York, Kearns & West

Observers

Alex Morris, California Energy Storage Alliance
Rory Stewart, Los Angeles Business Council

Call to Order and Agenda Overview

Joan Isaacson, LA100 Advisory Group meeting facilitator from Kearns & West, welcomed all the virtual meeting attendees. She noted that this was the last of four virtual sessions covering the topics scheduled for Advisory Group Meeting #11, and that this meeting would focus on questions from Advisory Group members as well as continued discussion about hydrogen eligibility in the LA Leads Scenario. She thanked the Advisory Group members for their continued patience and involvement in this virtual meeting format.

Timeline for Remaining Steps in LA100

Jaquelin Cochran, NREL LA100 Principal Investigator, provided an overview of the remaining steps in the LA100 study and previewed the upcoming Advisory Group Meeting #12 series set to begin on July 9. The July meetings will address draft pathways to 100% renewable energy, draft jobs and economic analysis, environmental analysis, which now includes morbidity and monetization of morbidity, mortality, and greenhouse gas emissions, and draft distribution grid analysis. She also previewed Meetings #13 and #14, the final two meetings, which will highlight results for all scenarios, preview the project's interactive website, and include a presentation from LADWP's Financial Services Office.

Cochran highlighted the importance of Advisory Group member feedback and urged members to continue providing critical feedback.

Major Themes from Advisory Group Member Questions and Discussion

- Deeper discussion is needed about options to help achieve the last 10% of renewable energy, to inform policy decisions that will be needed in preparation for achieving the last 10%. One option may be utilizing combustion for the last 10% due to the challenges.
- Allowing combustion of renewable hydrogen, both in- and out-of-basin, may be needed for flexibility to meet the last 10 percent, as turbines can also be run on methane if needed. There was concern that combustion generation using fossil fuels does not comply with the California mandate for a zero-carbon grid by 2045.
- When considering the reliability standard for the project, addressing multi-day challenges related to lack of wind and solar will be important.
- Although the study is not considering the electrification of medium- and heavy-duty vehicles quantitatively, it will be important to analyze impacts created by the ports.

Focused Follow-up Discussion: Hydrogen Eligibility in LA Leads

Cochran led a continuation of the May 21 discussion on hydrogen eligibility in the LA Leads scenario. She noted two assumptions guiding the scenario: no hydrogen combustion will occur for in-basin generation, but hydrogen combustion may be allowed at Intermountain Power Plant (IPP). She invited Advisory Group members to provide feedback on these assumptions, discuss the implications, and provide comments and questions.

Cochran provided a recap of pathways to creating storable fuel, which were discussed in greater depth by Paul Denholm during Session #2 of this meeting series. She noted that in scenarios that allow combustion, biofuels are assumed to be the fuel of choice for combustion generation. NREL is assuming this will be the case at least through 2030 due to market and infrastructure availability. NREL assumes that hydrogen will be the fuel of choice by 2045, although there is uncertainty about that timeline.

For the LA Leads scenario, Cochran noted two difficulties in generating electricity from storable fuel: production and transportation of hydrogen and the high cost of fuel cells. Both are significant considerations between now and 2040. Compared to other scenarios, LA Leads accelerates economy-wide decarbonization, whether or not hydrogen combustion is included. Cochran also highlighted distinctions between allowing and not allowing in-basin hydrogen combustion.

Major Themes from Advisory Group Member Questions and Discussion

- What is the source of the fuel for the biofuels? There are concerns about biofuels produced from agricultural or forest products.
- Could natural gas be an option to offset increased costs between now and 2030?
- Has carbon capture been considered for in-basin resources? These could reduce other emissions such as SOx, NOx, and particulate matter.
- What is the challenge with focusing the production, storage, and combustion of hydrogen at out-of-basin facilities?
- How is hydrogen produced?
- There are transmission alternatives that may help address challenges with constructing new transmission.
- What is the "higher near-term uncertainty on costs" by including in-basin hydrogen combustion?
- There was concern that environmental-justice issues are not being adequately addressed and are simply being "added" at the end rather than used as a foundation.
- Cost could be considered a social-justice issue.

- There was support for including hydrogen combustion both in-basin and out-of-basin, but only if produced from renewable resources.

Note, as a result of the feedback during this meeting, the scenario for LA Leads has been revised to allow in-basin hydrogen combustion (in addition to at IPP). See the revised scenario matrix at the end.

Focused Follow-up Discussion: Economics of Customer Adoption of Rooftop Solar

Ben Sigrin, Senior Research Engineer at NREL, provided background on the economics of customer adoption of rooftop solar, expanding on his presentation from Session #3 of Advisory Group Meeting #11. Sigrin gave an overview of how distributed energy resources are modeled, noting that economics is one of the primary factors guiding long-term, customer-driven solar adoption. Sigrin noted that the average upfront cost of a solar system today in Los Angeles is approximately $2,500 per kilowatt, varying based on the complexity of the installation and assuming no additional upgrades to the roof or building. Solar panels represent a small percentage of this cost, while customer acquisition, supply chain, and labor are some of the largest costs.

On average, one kilowatt of rooftop solar in Los Angeles generates about 1,400 kilowatt hours per year. Under the current policy of net metering, a credit is applied to the customer per unit, adding up to savings of about $0.19 per kilowatt. This could lead to an annual customer savings of about $273 per year per kilowatt installed.

While LA 100 is not designing tariffs, it analyzes two tariff possibilities: Net Billing and Net Metering. Sigrin discussed ways that these two tariff types value electricity. He also discussed other tariff types including value of solar and time of use.

Sigrin provided an overview of impacts that distributed storage would have on the system, noting that like solar, storage adoption is driven by economics and is valued by the nature of the payback period. NREL has projected that storage will be increasingly adopted with solar, depending on the sector. Sigrin noted that costs for solar are expected to decline through 2030, when more of the technical potential becomes economical.

NREL's analysis considers the link between the economics of distributed solar and the amount of solar realistically expected to be adopted. Much of this analysis is guided by historic trends of adoption of consumer technologies. Sigrin noted that changes in payback period over time can have an effect on the trend of saturation.

Major Themes from Advisory Group Member Questions and Discussion

- Battery storage will be a key component to successful deployment of local solar.
- What is the lifetime of rooftop solar, and are there operational costs?
- Does the analysis consider future increases in solar-panel efficiency?
- Adoption of solar-plus-storage systems seems prevalent today, partially due to tax credits. Is this something the study is examining? Without storage, solar panels don't add much value to the grid.
- How much of the total energy demand will be met with rooftop solar and battery systems? How much value does this add to the grid by acting as virtual peakers and by reducing distribution stress?
- LA's residential tariff includes an access charge based on the highest billing period's kilowatt-hour energy use in a year. This applies to all customers on the rate, not just net-metered solar. Storage has some value in this context.
- There was concern that because customer solar will always be more expensive than utility-scale solar, there may not be economic benefit to encouraging local solar over utility-scale solar.

General Q&A on Meeting #11 – Second Opportunity

- How was LAX and the Port determined to have such high technical potential for solar power?
    - Because this question was not answered during the meeting, NREL has provided the following answer to be included in this summary: NREL used two methodologies to assess four technologies of local solar technical potential in LA. First, they assessed developable rooftop potential using LiDAR data. For local solar, they also explored ground-mount, parking canopy, and floating solar sites net of building. (Note: floating solar sites are not relevant for the Port of Los Angeles discussion). These are consistent with NREL's typical methodology, and there is no distinct method for high-profile sites like the Port or Los Angeles International Airport (LAX). The technical potential should be understood as the maximum developable potential if all available area was used.
- Rooftop solar adoption impacts electrical demand and is a key input to the study, just as transportation and building electrification are.
- Can system load factor be added to the summary slides/tables? Also, consider adding slides showing daily load shapes by "season" for min/max and shoulder months.
- There was interest in further information on corrosion effects of hydrogen on the existing pipeline infrastructure, as well as methods to minimize the effect by mixing the hydrogen with natural gas.

Wrap-up and Next Steps

Isaacson thanked Advisory Group members, noting that the July meeting schedule has been confirmed, and will be shared shortly. She reminded members that the next meeting will have a similar format to this series of sessions, beginning July 9. She invited Advisory Group members to continue emailing questions to the project team.

Appendix A—Revised scenario matrix to allow RE-derived hydrogen combustion in LA Leads (in and out of basin)

Details on specific assumptions will be provided during Advisory Group Meeting #12.

		LA100 Scenarios								
		Moderate Load Electrification				High Load Electrification (Load Modernization)				High Load Stress
		SB100	LA-Leads, Emissions Free (No Biofuels)	Transmission Renaissance	High Distributed Energy Future	SB100	LA-Leads, Emissions Free (No Biofuels)	Transmission Renaissance	High Distributed Energy Future	SB100
	RE Target in 2030 with RECs	60%	100%	100%	100%	60%	100%	100%	100%	60%
	Compliance Year for 100% RE	2045	2035	2045	2045	2045	2035	2045	2045	2045
Technologies that do not vary in eligibility across scenarios	Solid Biomass	N	N	N	N	N	N	N	N	N
	Fuel Cells	Y	Y	Y	Y	Y	Y	Y	Y	Y
	RE-derived Hydrogen Combustion	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Hydro - Existing	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Hydro - New	N	N	N	N	N	N	N	N	N
	Hydro - Upgrades	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Nuclear - New	N	N	N	N	N	N	N	N	N
	Wind, Solar, Geothermal	Y	Y	Y	Y	Y	Y	Y	Y	Y
	Storage	Y	Y	Y	Y	Y	Y	Y	Y	Y
Technologies that do vary	Biofuel Combustion	Y	No	Y	Y	Y	No	Y	Y	Y
	Natural Gas	Y	No	No	No	Y	No	No	No	Y
	Nuclear - Existing	Y	Y	No	No	Y	Y	No	No	Y
Repowering OTC	Haynes, Scattergood, Harbor	N	N	N	N	N	N	N	N	N
RECS	Financial Mechanisms (RECS/Allowances)	Yes	N	N	N	Yes	N	N	N	Yes
DG	Distributed Adoption	Moderate	High	Moderate	High	Moderate	High	Moderate	High	Moderate
Load	Energy Efficiency	Moderate	Moderate	Moderate	Moderate	High	High	High	High	Reference
	Demand Response	Moderate	Moderate	Moderate	Moderate	High	High	High	High	Reference
	Electrification	Moderate	Moderate	Moderate	Moderate	High	High	High	High	High
Transmission	New or Upgraded Transmission Allowed?	Only Along Existing or Planned Corridors	Only Along Existing or Planned Corridors	New Corridors Allowed	No New Transmission	Only Along Existing or Planned Corridors	Only Along Existing or Planned Corridors	New Corridors Allowed	No New Transmission	Only Along Existing or Planned Corridors
WECC	WECC VRE Penetration	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate