Biden Energy Plan: Engineering and financial analysis of achieving 100% carbon-free generation by 2035

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March 9, 2021

- Analysis is based on engineering data and actual load, solar, and wind characteristics.
- This information is intended to drive discussion and is not a plan or recommended course of action.

Key attributes of the Biden Energy Plan

- 100% carbon free power by 2035
- Increased energy efficiency standards
  - Retrofit 4 million buildings and 2 million households with more energy efficient appliances
  - Net-zero emissions for all new buildings by 2030
- Promote EV deployment via tax incentives, rebates for IC trade-ins, and 500,000 new public charging stations across the U.S.
  - Transition 3 million government vehicles to zero-emission vehicles
  - All new public transport buses are zero emission by 2030
  - Convert all school buses to zero emission within five years
- Install 500 million solar panels and 60,000 made-in-America wind turbines within five years, including eight million solar roofs and community solar energy systems
- "Buy Clean and Buy America" standards to incentivize production of low-carbon building and construction materials, like steel and cement, here in the United States

Many claim that carbon-free electricity is reliable and economic

- Rocky Mountain Institute – Clean Energy Portfolio is likely more cost-effective than running existing gas plant by the early 2030s
- Energy Innovation & Vibrant Clean Energy – coal plants can be replaced by clean energy with lower costs
- Mark Jacobson, Stanford and The Solutions Project – 100% renewable by 2035
- National Academies of Sciences, Engineering, Medicine – Deep decarbonization by 2050 is technically feasible and spending will be manageable
  - 75% non-carbon-emitting target for electricity by 2030
- Goldman School of Public Policy, UC Berkeley – 90% carbon-free electricity by 2035
- Various studies from universities, NGOs, and think tanks

UC Berkeley – 90% carbon-free electricity is technically and economically achievable by 2035

- Key Assumptions
  - All coal plants are retired
  - No new gas plants are built
  - Retain 2/3 of existing gas capacity
  - Existing hydro and nuclear are retained (except announced retirements)
- New generation installed by 2035 would equal existing total capacity
  - 575 GW of new wind (104 GW installed as of 2019)
  - 525 GW of new solar (61 GW installed as of 2019)
  - 100 GW of battery storage (2 GW installed as of 2020)
  - Existing US capacity is around 1,000 GW
- 90% Clean being "more economic" than alternative depends on:
  - $1.2 trillion in health benefits through 2050 - $20/MWH
  - Limited investment in new transmission (renewables & storage are built locally)
  - Unrealistic "No New Policies" case that grows coal energy generation while reducing gas compared to present (drives health benefits of 90% Clean case)

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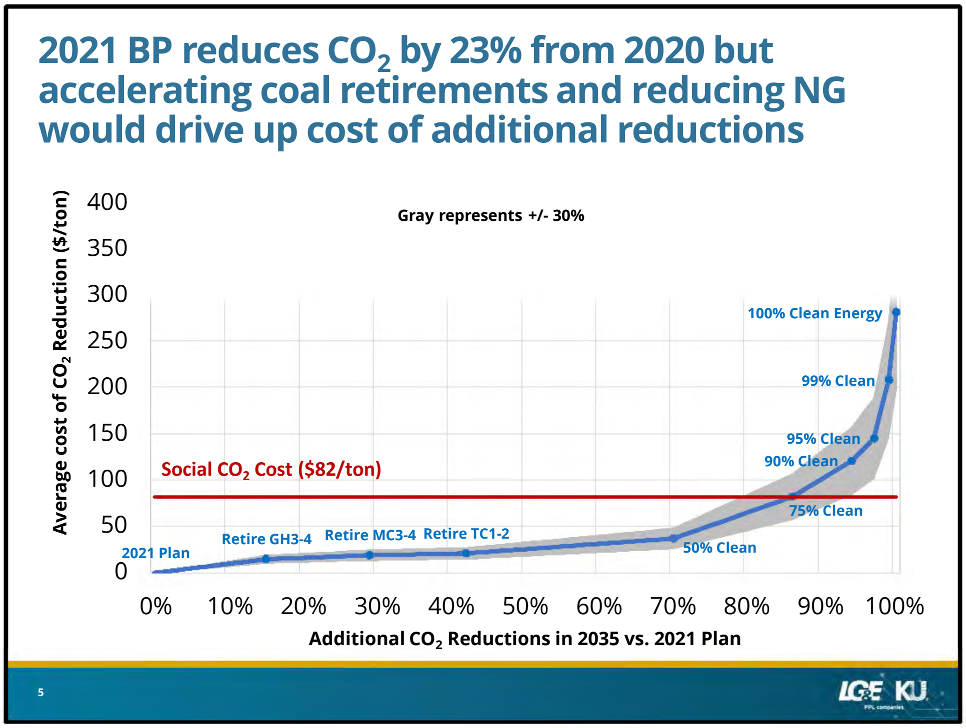
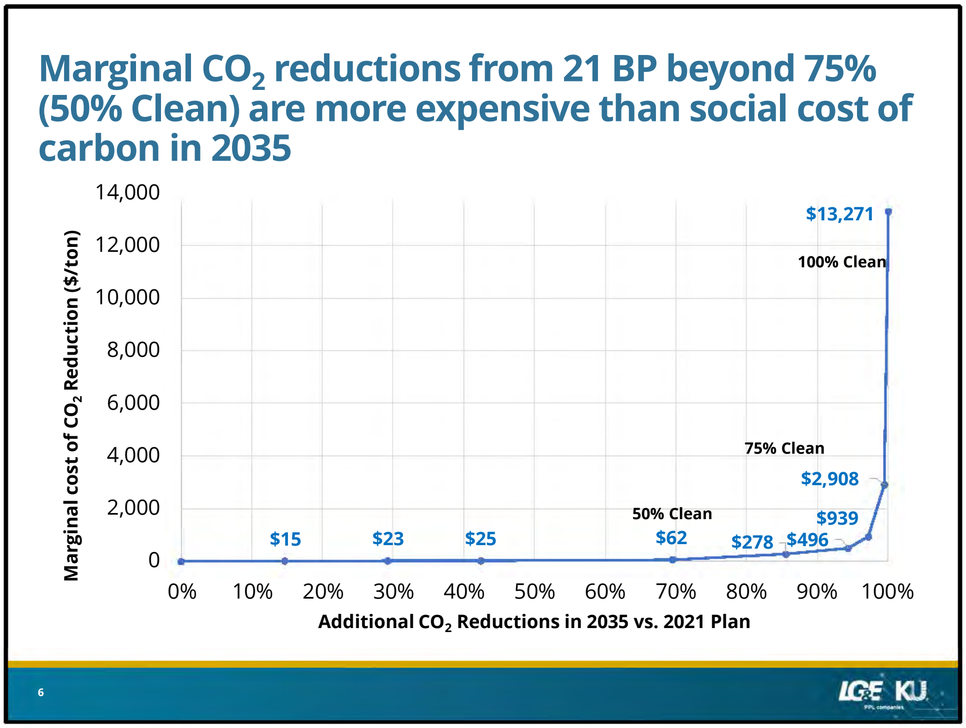
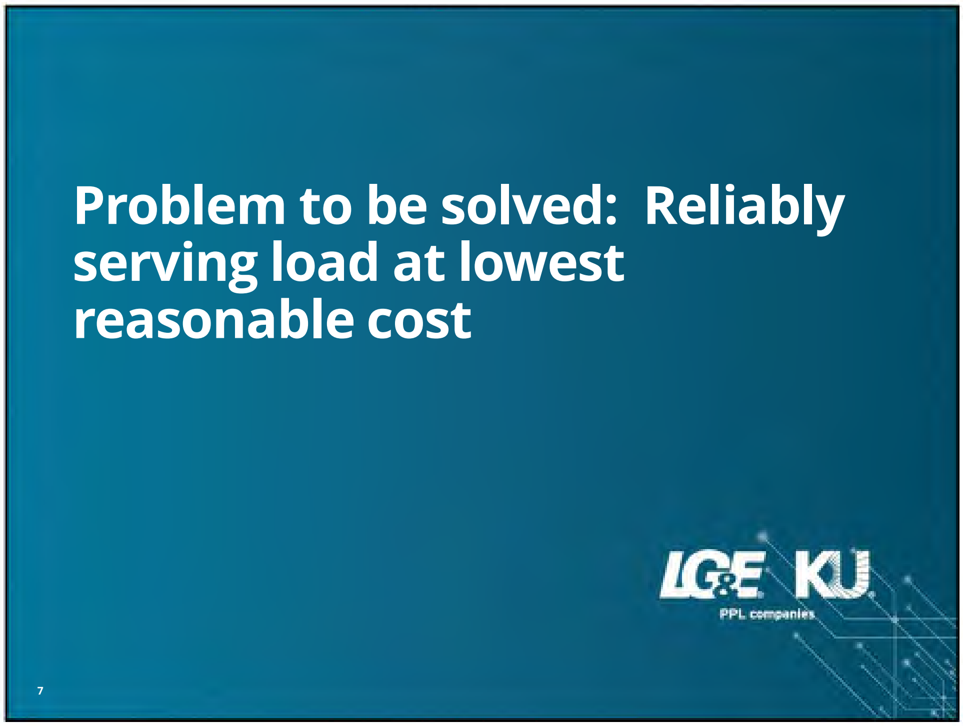
- Note that 100 GW of installed battery capacity is consistent with 2030 goal of U.S. Energy Storage Association.
- Assumption that limited transmission investment is required at odds with most other studies that support high concentration of renewables.



- All CO2 volumes were calculated in short tons.
- Natural gas is important to keeping our cost of CO2 reductions affordable.
- According to 2021 BP – CO2 emissions will decline from 30 million tons in 2020 to 23 million tons in 2035. Reductions prior to 2035 are due to retiring coal and building NGCC. It can be argued that the cost of these CO2 reductions is negative since economics are driver for retiring these units – not CO2 emission reductions.
- Per recent solar contract price, about 1 million tons could be reduced for between negative $5 / ton (assuming REC sales) to positive $5 per ton with no REC sales (compared to marginal cost of coal).
- All coal plants are assumed to be replaced with NG NGCC.
- 50% clean cases and above assume post-2035 coal plants are only replaced with renewables and storage (i.e., only pre-2035 NGCCs are built).
- Social cost of carbon in 2035 is $67 / metric ton in $2020 per recent Biden Admin. change. Converting to short tons and escalating at 2% yields $82 / short ton.



- Marginal cost of CO2 reductions calculated from “middle” of average CO2 costs from prior slide.


Problem to be solved: Reliably serving load at lowest reasonable cost
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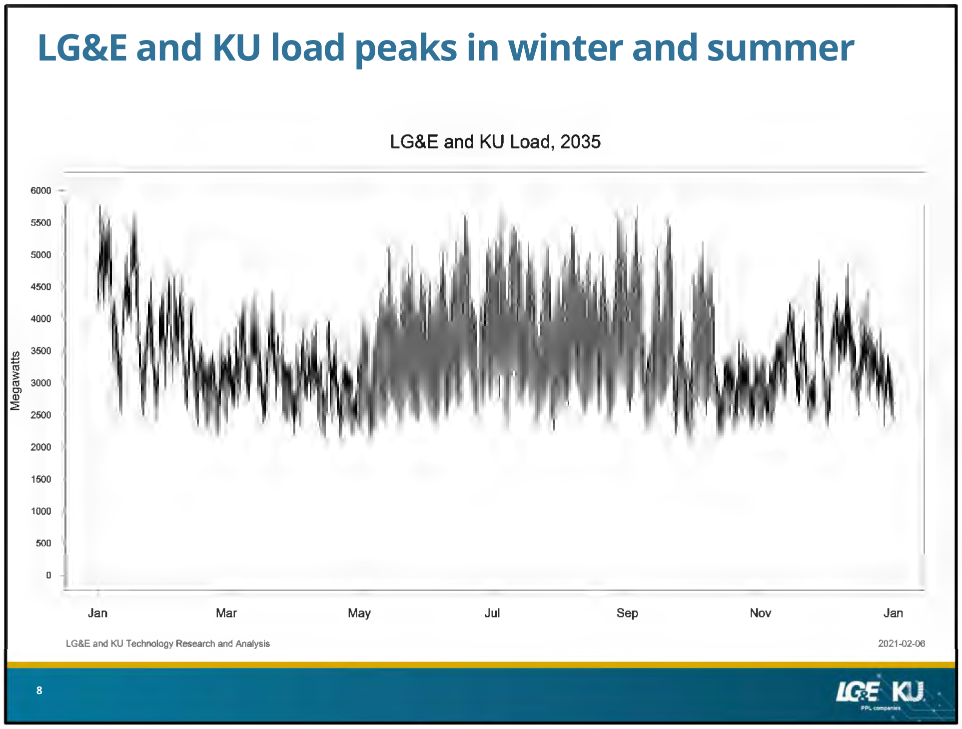
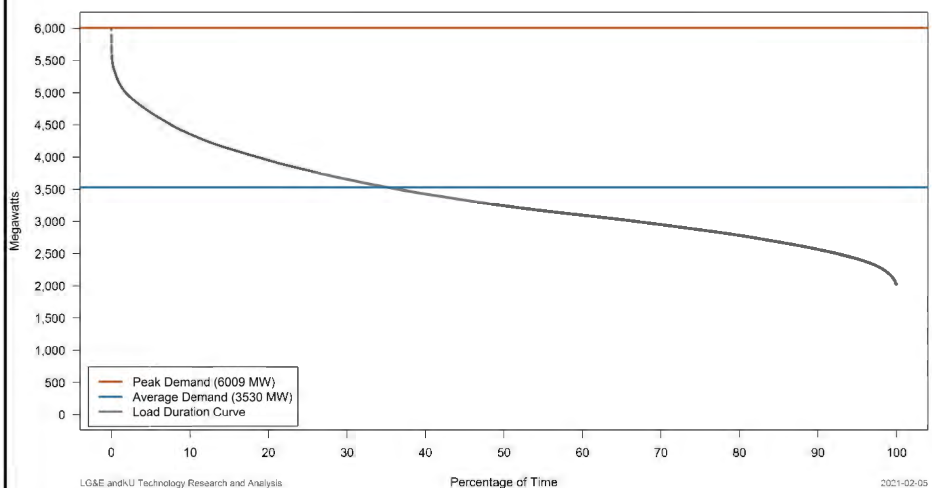


1-minute load

60% of LG&E and KU winter demand occurs at night

2035 Load Duration Curve




Mix of wind, solar, and storage required to reliably serve 2035 load
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Viable carbon-free technologies are limited today

- Existing carbon-free technologies are solar, wind, and lithium-ion batteries
- Nuclear is assumed not to be an option by 2035 given development lead time and likely resistance to new greenfield sites
- Current price of "green" hydrogen (H_2) is around $80 / MMBtu and supply is limited so not used in first phase
- Rush to build existing carbon-free generation would likely drive costs higher than in status quo
  - Analysis assumes carbon-free technology costs stay at today's levels
- Assumed that all future generation is self-build
- No incremental cost for new transmission infrastructure included but material investments would be required due to reliance on inverter technology (see "Transmission Considerations" appendix)

2035 generation resource cost assumptions for Biden Energy Plan analysis

	Solar	Kentucky Wind	Battery Storage*	Hydrogen Combined Cycle
Capital Cost ($/kW)	$1,042	$1,753	$1,075	$1,055
Fixed O&M ($/kW-yr)	$6.24	$34.55	$17.83	$73
Variable Cost ($/MWh)	$0	$0	$0	$105
Capacity Factor	24.7%	24.6%	--	85%

* 1 MW and 4 MWh lithium-ion energy storage system.
Solar, wind, and storage are higher than otherwise would be the case given increase in demand nationwide.
Hydrogen CCGT costs same as projected for NG unit.
Distributed solar was not evaluated given its higher installed cost and lower capacity factor compared to utility scale.
KY wind used because out of state sites assumed to be utilized to meet wind needs in those states and avoid the need to build large-scale interstate transmission by 2035.

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Resources required to serve load were determined by utilizing real-world data

- All load, solar, and wind data based on actual 1-minute data from 2018
- 2035 load forecast was allocated to 2018 1-minute pattern
- Solar generation based on actual data from 67 sites across KY
- Wind generation based on actual data from best KY site
- Thousands of generation portfolios were evaluated to identify lowest-cost options
- No load uncertainty, reserve margin, or contingency/operating reserves were assumed

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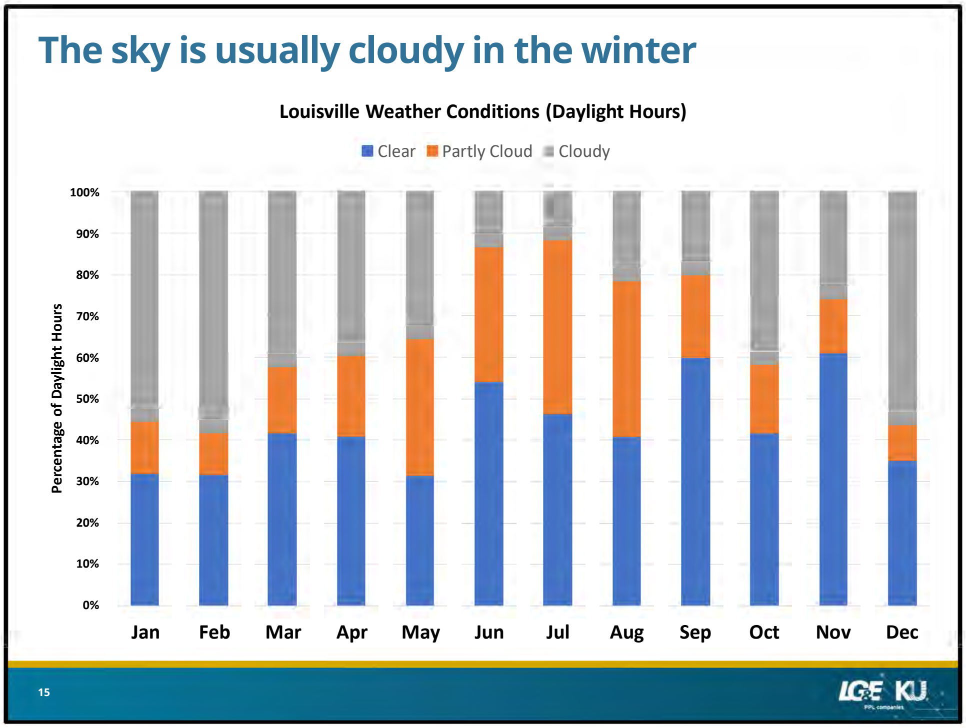

- Clouds greatly impact size of solar and battery storage.

Serving load with renewables and battery storage would require $74 billion investment

	2021 BP		Biden Scenario	
	Capacity (MW)	Energy (TWh)	Capacity (MW)	Energy (TWh)
2035 Peak Demand/Energy Requirements	6,009	31	6,009	31
Coal	2,900	15	--	--
Gas	4,076	16	--	--
Solar	10	0	18,000	39
Wind	--	--	9,000	19
Storage used to serve load	--	--	23,000	10
Unused solar/wind	--	--		23
Inverter and battery losses				4
Total fuel costs ($B)	0.8		0	
New investment by 2035 ($B)	2		74	

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

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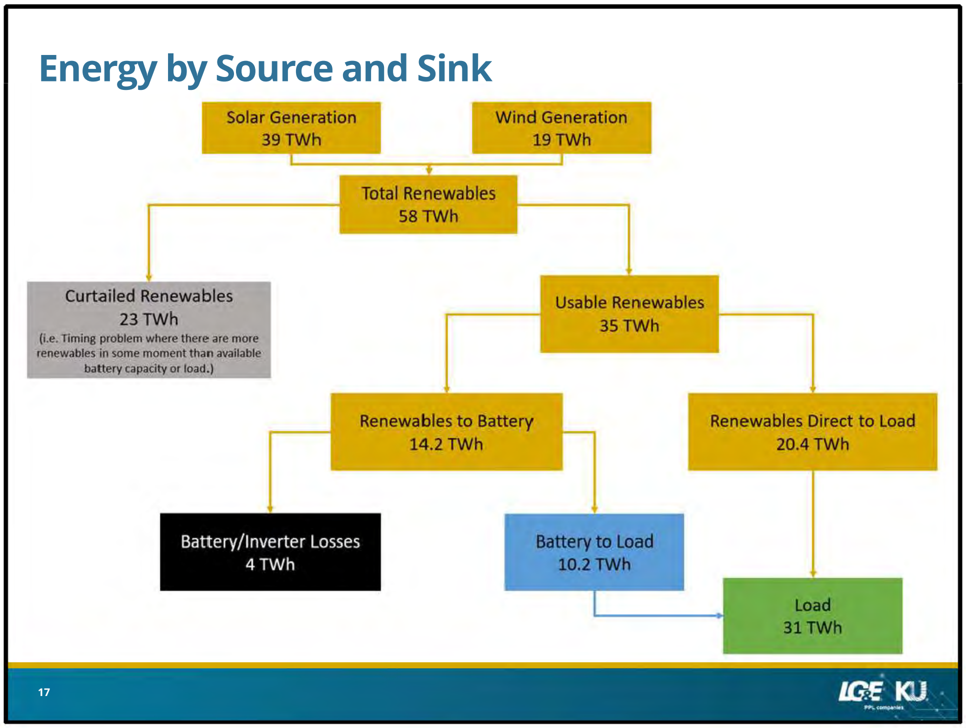
See next slide for details on sources and sinks for generation.


Energy by Source and Sink
Solar Generation 39 TWh
Wind Generation 19 TWh
Total Renewables 58 TWh
Curtailed Renewables 23 TWh (i.e. Timing problem where there are more renewables in some moment than available battery capacity or load.)
Usable Renewables 35 TWh
Renewables to Battery 14.2 TWh
Renewables Direct to Load 20.4 TWh
Battery/Inverter Losses 4 TWh
Battery to Load 10.2 TWh
Load 31 TWh
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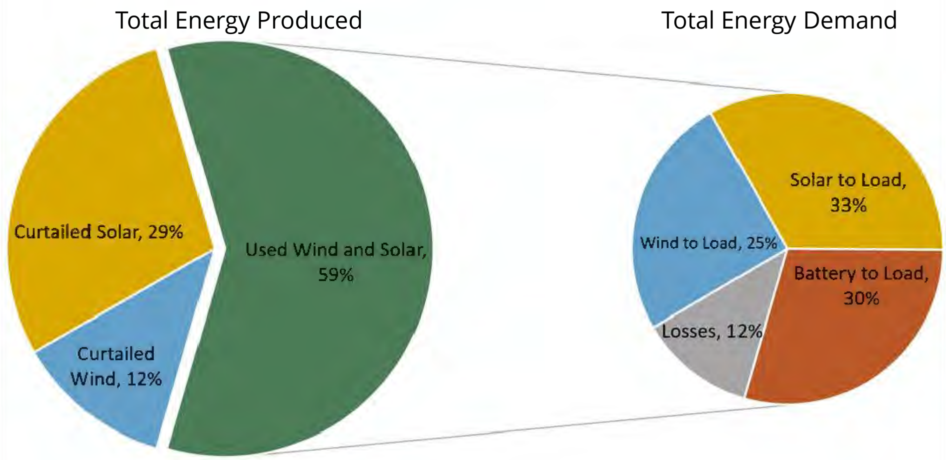
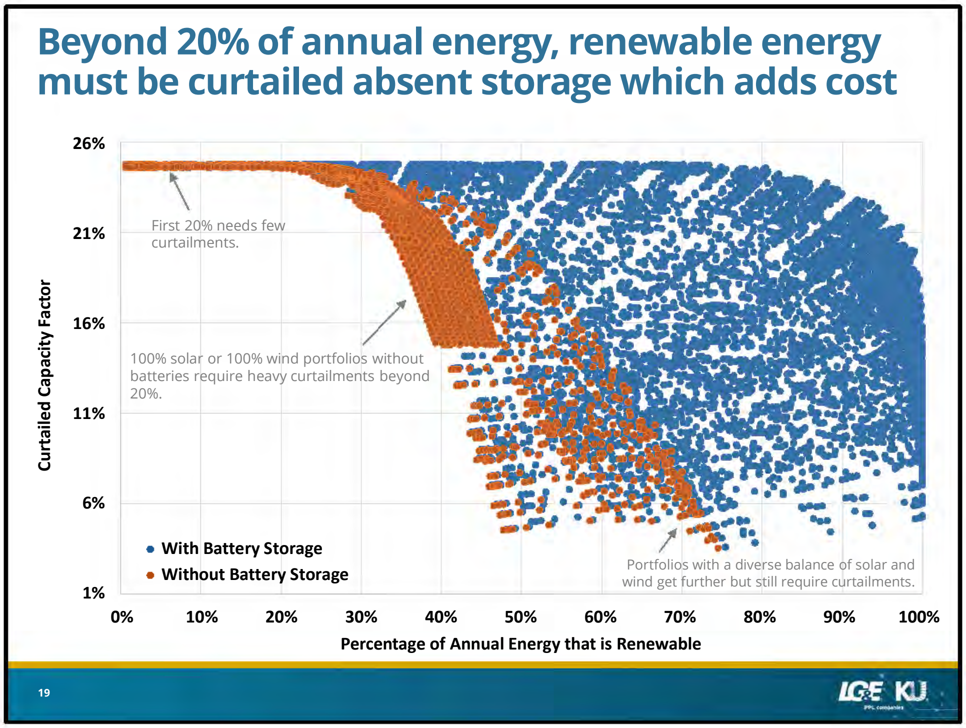
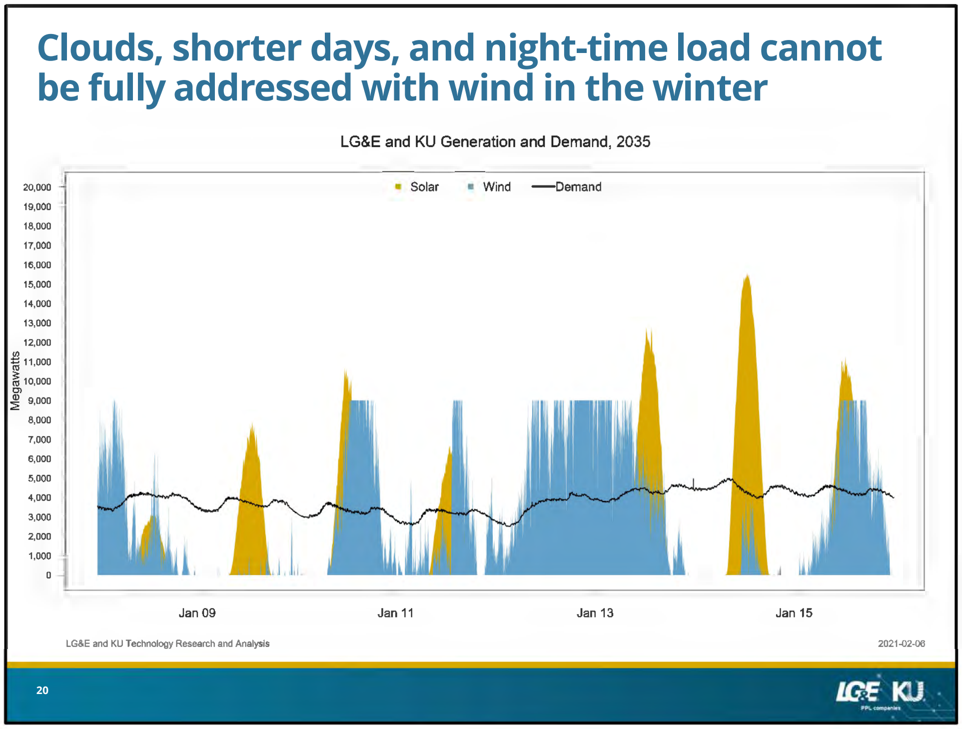
41% of solar and wind must be curtailed

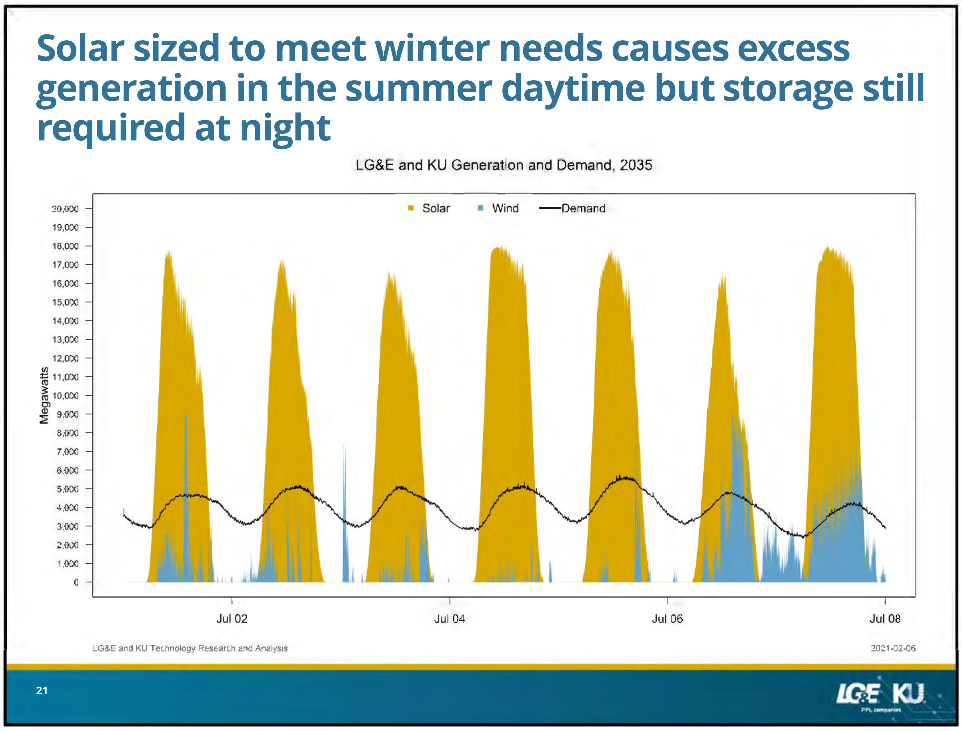




- Dots represent various alternative combinations of wind, solar, and storage that the model evaluated.
- Best performing portfolios are along the top part of the chart. Hence, adding storage begins to make sense when annual renewable energy reaches 20 -30 percent of annual energy.
- However, adding storage just adds to overall costs - building electron warehouses in order to move energy around in time and energy losses associated with round-trip storage.
- Results are consistent with CA's actual experience at around 25 percent annual renewables with energy dumping to AZ, adding storage, and curtailing renewables.



- "White" area below the load curve would be unserved energy absent being served by storage.
- Generation above load would be used to charge batteries assuming capacity and energy volume is available. If not, generation would need to be curtailed.



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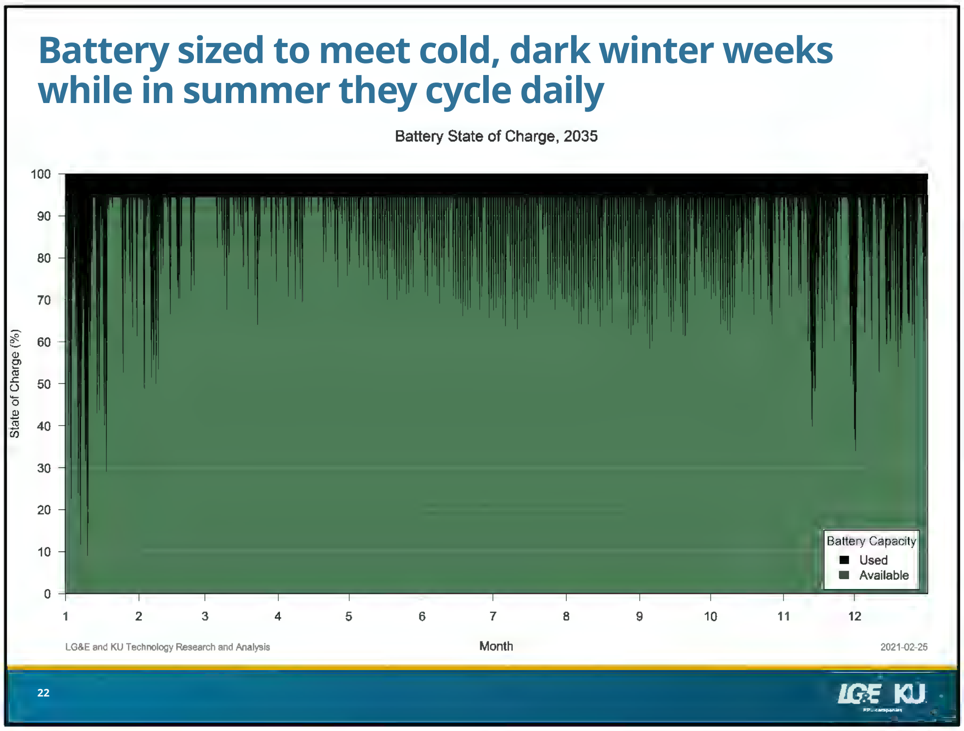


- Even if only needed for a brief period, battery must be sized to address load.
- Battery size is driven by i) limited window of time to charge due to availability of excess solar/wind and ii) duration of energy required to serve load (e.g., night) when solar/wind is not able to meet load.

Conclusion: Existing renewable technology is expensive to reliably serve 100% of load

- Serving winter load is challenged by clouds, less daylight, and high load for heating
- Cost is much higher than what zero CO_2 proponents believe
  - $74 billion investment vs. $2 billion in 2021 BP
  - Annual fixed charge of capital costs are likely 10x greater than fuel savings
- Such a huge increase in energy costs would have dramatic impacts on economy, jobs, and load

Breakthroughs in Green H_2 prices would lower costs and require fewer renewables and no battery storage

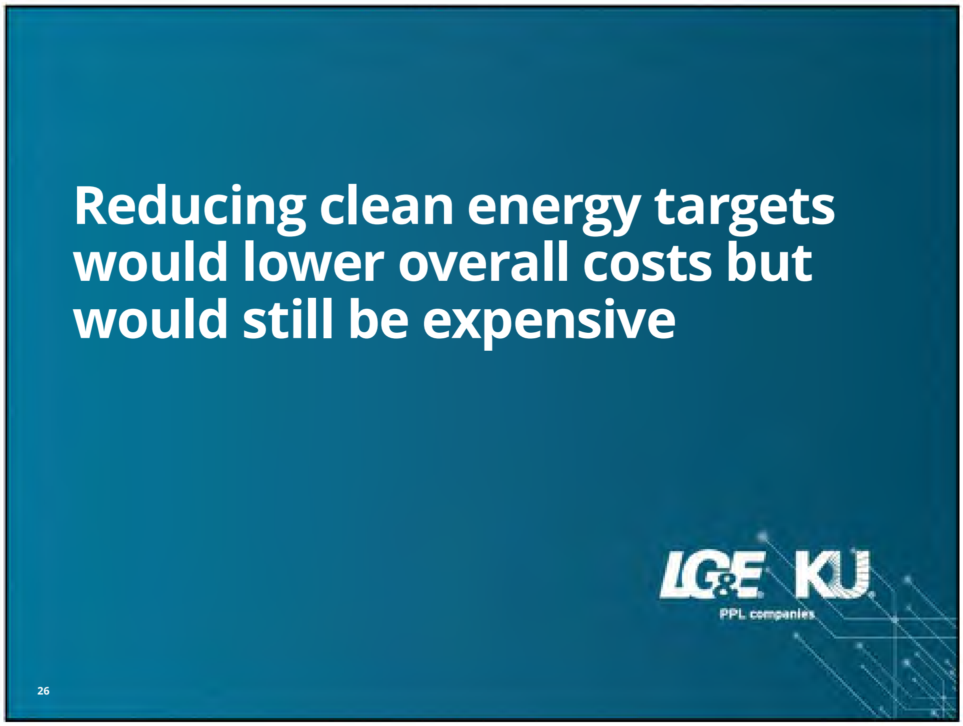
- Evaluated H_2 improvements to reduce cost
  - Green H_2 is assumed to be priced in 2035 at today's price of Grey H_2 of $10 to $22 /MMBtu (used $16.48 / MMBtu in the analysis)
  - Future H_2-burning turbines and infrastructure assumed to cost the same as today's NG-based system

With favorable H_2 assumptions, required investment is 6x 2021 BP but fuel costs also increase by 3-fold

	2021 BP		Existing Technology		Add Hydrogen	
	Capacity (MW)	Energy (TWh)	Capacity (MW)	Energy (TWh)	Capacity (MW)	Energy (TWh)
2035 Peak Demand/Energy Requirements	6,009	31	6,009	31	6,009	31
Coal	2,900	15	--	--	--	--
Gas	4,076	16	--	--	--	--
Solar	10	0	18,000	39	4,500	10
Wind	--	--	9,000	19	90	0.2
Storage	--	--	23,000	10	0	0
Hydrogen	--	--			6,000	21
Unused solar/wind	--	--		23		0.5
Inverter and battery losses				4		0
Total fuel costs ($B)	0.8		0		2.5	
New investment by 2035 ($B)	2		74		13	

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

- H2 capacity and dispatchability eliminates the need for battery storage.
- Solar and wind are added to avoid high energy cost of using H2 (over $100/MWh).
- Note that solar/wind make up about 1/3 of total load so annual energy limit is reached consistent with slide #19. This minimizes unused solar/wind and eliminates the need for storage.


Reducing clean energy targets would lower overall costs but would still be expensive
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Getting to 50% Clean by 2035 will still be expensive and getting the last 10% more than doubles required investment compared to 90% Clean

	2021 BP		50% Clean		75% Clean		90% Clean		100% Clean	
CO_2 Emissions (millions of short Tons)	22.6		6.5		3.1		1.3		0	
	MW	TWh	MW	TWh	MW	TWh	MW	TWh	MW	TWh
Load	6,009	31	6,009	31	6,009	31	6,009	31	6,009	31
Coal	2,900	15	--	--	--	--	--	--	0	0
Gas	4,076	16	4,300	15	3,700	8	3,300	3	0	0
Solar	10	0	7,200	15	9,300	20	13,100	28	18,000	39
Wind	--	--	700	2	3,800	8	4,300	10	9,000	19
Hydro	134	0.3	134	0.3	134	0.3	134	0.3	134	0.3
Battery Storage	--	--	3,400	8	6,100	10	10,700	12	23,000	10
Unused Solar/Wind	--	--	--	11	--	2	--	6	--	23
Battery/Inverter Losses	--	--	--	6	--	4	--	4	--	4
Fuel costs ($B)	0.8		0.4		0.2		0.1		0	
New investment by 2035 ($B)	2		12		23		33		74	

*Existing hydro units remain in service in all scenarios.
**In 2021 BP, MC1, MC2, BR3, GH1, and GH2 are replaced by 1,400 MW of NGCC capacity. ibV PPA is not included in 2021 BP.

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- New Investment in “Clean” scenarios is incremental to 2021 BP.
- Large increase in cost to go from 90% Clean to 100% Clean was the reason the Berkeley study stopped at 90%. We are told by someone involved with the study that the original intent was to get to 100% Clean.

Alternative technology and markets

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Rapid breakthrough in technologies is required very soon to achieve mass adoption by 2035

- H_2 – LCRI is focused on at least a decade of research
  - Green H2 would require massive renewable buildout as well because high-capacity factor for electrolyzer drives economics
  - Broad commercial application not consistent with 2035 goal
    - McKinsey & Co. estimate 14% of power generation from H_2 by 2050
- CCS – Despite research, economic and legal (sequestration) challenges remain large
  - Elon Musk offered $100 million prize for best project
  - Not likely to be applied to existing coal units
- Nuclear
  - Large scale – 4 licenses (FPL, DUK, DOM, DTE) approved for 6 units
  - Small Module – lots of research and interest worldwide but not much progress on large scale commercial deployment
    - License process not materially different from large scale reactors

Joining an RTO would expand geography but does not fundamentally alter technology challenges

- Weather impacts on load are correlated
- Solar challenges remain
  - Day/night limitations not materially altered
  - Winter clouds are problematic throughout the Midwest and East
- Best wind sites would likely be needed to serve existing RTO load
- Battery storage supports the grid best near load (see "Transmission Considerations" appendix)
- Significant transmission would need to be built if new generation is not located in proximity to existing generation

Conclusions

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Biden Energy Plan goal of carbon-free electricity by 2035 is extremely aggressive

- Achieving carbon-free electricity by 2035 with today's technology seems unlikely and would be wildly expensive
- Assuming breakthrough in Green H_2 production would reduce costs dramatically but such a development is highly speculative
  - H_2 generation eliminates the need for battery storage but maybe not for H_2 production to achieve high capacity factor for production
  - Renewables still deployed to reduce high H_2 generation fuel costs
- Other zero carbon technologies not likely to be commercially deployed on a broad scale on the necessary timeline
- A rapid transition to carbon-free electricity by 2035 would likely be extremely disruptive to the economy and have a large, negative impact on jobs and load

Appendix: Transmission Considerations

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Transmission Provides Operating Reliability

- Transmission's role is to plan, construct, and maintain reliable operation of the LG&E and KU transmission system while accommodating new generation, generation retirements, and serving firm load and firm transmission service obligations.
- Planning the transmission system is achieved primarily thru completion of Steady State and Dynamic Stability Analysis and relies heavily on forecasts provided by generators and load serving entities.
  - *Steady State Analysis:* *Identifies overloads and voltage violations on the Transmission System once it has reached a state of equilibrium.*
  - *Stability Analysis:* *Identifies issues with voltage and frequency on the Transmission System immediately after a fault is cleared.*
  - *Violations identified through analysis can be resolved by system operating instructions, additions and/or upgrades to primary equipment (lines, power transformers and substn equipment, capacitors, etc.).*

Transmission Summary – Biden Energy Plan

- Transmission requirements to convert existing spinning and conventional generation to inverter-based generation (i.e., solar, wind, and batteries) are known and manageable.
- **Location** of new inverter-based generation, and subsequent retirement of existing generation, is a key factor in planning and constructing the transmission system for reliable operations.
- The significant generation turnover and pace of change would present many challenges.
  - Accurate forecasts of future generation, generation retirements, and load will be critical for a successful transition.
  - As part of the eastern interconnection, similar transitions from neighboring transmission system will require significant coordination and potentially other transmission upgrades.
  - Timing to complete major upgrades (e.g., siting, permitting, and construction of new high voltage lines) are uncertain.
- An accurate cost estimate range is impossible without further details, including location of new generation.

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2300 MVARs is the reactive capacity of LG&E/KU existing fleet

How Would Transmission Planning Support the Transition to Inverter-Based Resources?

- Build additional off-peak models to analyze solar and wind generation and charging of batteries.
- Perform Steady State Analysis
  - Identify new transmission equipment required to accommodate inverter-based generation and retire existing generation.
  - Identify and mitigate voltage issues and thermal overloads of existing transmission equipment.
  - While analyzing our transmission system, identify voltage issues and thermal overloads on neighboring transmission systems.
- Perform Dynamic Stability Analysis
  - Identify and mitigate issues related to voltage, frequency, rotor angle, and transient stability.

Equipment Required for New Generation & Thermal Overload Mitigation

- New interconnection facilities and network upgrades will be required to accommodate 18GW of solar and 9GW of wind generation. Network upgrades and costs would be minimized if located at our near existing generation facilities or major substations.
- Location of the significant amount of required storage (23GW) will likely require major network upgrades, even if dispersed geographically across the state.
- Additional high voltage interconnections with neighboring transmission systems will be considered to add system support.

Maintaining Voltage Support

- Inverter-based resources can provide voltage support but at the expense of reducing real power.
  - There are no existing requirements to oversize inverters (capacity margin) to provide necessary voltage support.
- Additional support or a more economical solution may be to install voltage supporting equipment. This type of equipment is typically considered "primary", located in a substation, and can be large and costly (see below).
  - Examples of such primary equipment might be capacitors and static var compensators
- Resources and/or additional voltage support equipment installed at or near existing generation plants or substations may provide support at the lowest cost by locating near existing transmission capacity.

2300 MVARs is the reactive capacity of LG&E/KU existing fleet

Maintaining Frequency Control

- Inverter-based resources can provide frequency support. Appropriate real power must be held in reserve in case needed to support a low frequency system event. Real power must be reduced to assist in a high frequency system event.
  - There are no existing requirements to oversize inverters (capacity margin) to provide necessary frequency support.
- Additional support or a more economical solution may be to install frequency supporting equipment. A synchronous condenser could provide some frequency support in addition to voltage support.
  - Similar to primary equipment used to support voltage, synchronous condenser are large and costly.
- Resources and/or additional frequency support equipment installed at or near existing generation plants or substations may provide sufficient support at the lowest cost by locating near existing transmission capacity.

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HVDC lines are only cost effective if power is transported at least 400-500 miles. Therefore, not a good option for Kentucky.

Open Access Transmission Tariff (OATT) Services Should be Considered

- Evaluation of existing ancillary services provided to third party transmission customers will need to be considered.
  - LG&E and KU are obligated to offer ancillary services via the OATT
  - Approximately 600 MWs of third party peak load currently subscribe for voltage control, frequency response, operating reserves, and imbalance services.
  - OATT ancillary services purchased and offered to others should be considered when making final resource decisions.

Estimated transmission expense is relatively small compared to generation costs.

- As noted, the location of future inverter-based resources will drive the necessary transmission upgrades and cost.
- Evaluation of the location should consider transmission costs to determine the least cost option.
- It is difficult to estimate transmission expense without a more detailed breakdown of future capacity and location. However, transmission costs are typically a relatively small percentage of generation costs.
  - *For example, at an estimated cost of $74 billion for the inverter-based resources, a $7.4 billion transmission cost estimate would equate to 10% of the generation cost.*
  - *By comparison, the current rate base of the entire LG&E and KU transmission system is approximately $850 million.*
- One approach could be to develop estimates in a phased approach using the current generator interconnection queue. Even order-of-magnitude estimates would require significant resources and time to accomplish.