THE POWER BUREAU, LLC

ENERGY PLANNING & PROCUREMENT

February 26, 2024

TO: Anthony Star, Senior Advisor and Chief of the Planning & Procurement Bureau, Illinois Power Agency (IPA)

FROM: Mark Pruitt, Principal, The Power Bureau

SUBJECT: Solar Associations Comments to the IPA Draft Policy Study

On behalf of the Clean Grid Alliance, the Solar Energy Industry Association, the American Clean Power Association, and the Coalition for Community Solar Access (the "Associations") I am submitting to you the following comments to the IPA Draft Policy Study ("Draft Study"), inclusive of the Errata and supplemental data releases issued by the IPA as part of the study process.

The Associations appreciate the efforts of the IPA to create the Draft Study and encourages the IPA to enhance the Draft Study to aid policymakers and stakeholders develop policies that will provide Illinois consumers with access to dependable, affordable, and sustainable energy. To accomplish this, the Draft Study should be amended to ensure the following:

- **Completeness.** All parties recognize that deploying energy storage will manifest a wide range of economic impacts, and that not all economic impacts can be calculated at this time. However, the Draft Study should be updated to consider and report on at least all primary and known benefits that can result from energy storage deployments.
- **Clarity.** Policymakers and the public need to understand the bottom-line regarding the need for and economic impacts of deploying energy storage at scale in Illinois. The Draft Study should be updated to aggregate and simplify the results of the various economic analyses undertaken by the IPA.

Background. Senate Bill 1699 (SB 1699) was passed on November 9, 2023 and signed by the Governor on December 8, 2023 as Public Act 103-0580. The Act directs the Illinois Power Agency to conduct the Policy Study to evaluate the potential impacts of the deployment of various technologies in Illinois (e.g., energy storage, offshore wind, and High Voltage DC transmission projects). The IPA followed the below schedule in furtherance of the Study:

- **August 23,2023.** The IPA announced the development of the Study and issued a the "Illinois Power Agency Policy Study Technical Information Requests."
- **September 29, 2023.** The IPA issued the "House Bill 3445 Policy Study Request for Stakeholder Feedback" with an October 20, 2023 deadline for responses by stakeholders.
- **October 30, 2023.** The IPA posted the responses to the request for Stakeholder Feedback.

- **January 22, 2024.** The IPA issued the Draft Policy Study with a February 12, 2024 deadline for comments by stakeholders.
- **February 1, 2024.** The IPA and its consultants attended a meeting with the Associations and their members to discuss aspects of the Study. In response to certain questions, the IPA provided immediate responses as well as commitments to provide additional details concerning the inputs and outputs of the various models used in support of the Study.
- **February 6, 2024.** The Associations' representative contacted the IPA to request a status on the provision of the data requested at the February 1, 2024 meeting. The IPA indicated that the data collected was underway with a targeted delivery date of February 7, 2024.
- **February 7, 2024.** The IPA notified the Associations' representative that the IPA would be issuing an Errata to the Study.
- **February 8, 2024.** The IPA issued an Errata to the Draft Study which presented material changes amounting to billions of dollars in corrections to primary values as presented in the below table.

TABLE 1: INVENTORY OF ERRATA (IPA DRAFT POLICY STUDY)

Reference Location of Changed Value in Errata	Value Element	Materiality of Errata		
		Value in Draft Study	**Value in Errata**	**Value Differential ($, %)**
Appendix E: Figure 23 Summary Projections, 2030-2049 (Nominal)	Value of Storage (Energy Revenue, $/MWh)	$0.02	$16.23	**811.5%**
Appendix E: Figure 24 Summary Projections, 2030-2049 ($2022)	Value of Storage (Energy Revenue, $/MWh)	$0.01	$10.13	**1,013.0%**
Appendix E: Figure 25 Summary Projections, 2030-2049 (NPV with 2% Discount Rate)	Value of Storage (Energy Revenue, $/MWh)	$0.01	$8.15	**815.0%**
Appendix E: Table 2 Summary Projections, 2030-2049 Contract Period ($1,000 Nominal)	Value of Storage (Energy Revenue, $1,000's)	$2,650	$2,649,688	**$2.6 billion 999.9%**
Appendix E: Table 6 Distributed Project Annualized ($2022) Summary	Cost of Storage (Cost/Year, $1,000's)	$253,129	$197,691	**-$1.1 billion -21.8%**
	Revenue of Storage (Energy Revenue/Year, $1,000's)	$13	$12,947	**$259 million 99,492.3%**
	Net Cost of Storage (Total Cost/Year, $1,000's)	-154,310	-$86,138	**-$2.9 billion -44.2%**
	Unit Cost of Storage (Cost, $/MWh)	$10.13	$7.92	**-21.8%**
	Unit Revenue of Storage (Energy Revenue, $/MWh)	$0.00	$0.52	**99,492.3%**
	Net Unit Cost Storage (Total, $/MWh)	-6.17	-$3.45	**-44.2%**
Appendix E: Table 7 (Table 8-11) Project Annualized ($1,000 2022) Summary	Storage (Energy Revenue, $1,000's)	$83	$947	**$17 million 99,537.3%**
	Storage (Total, $1,000's)	-154,310	-$86,138	**-$2.9 billion -23.2%**

- **February 9, 2024.** The Associations requested that the IPA extend the deadline for comments to February 26, 2024.
- **February 13, 2024.** The IPA extended the deadline for comments to the Draft Study and committed to posting information concerning the data and sources used in the Draft Study.
- **February 16, 2024.** The IPA provided notice that the IPA had discovered additional material errors in the Draft Study including:
  1. Excluding the Federal Investment Tax Credit for offshore wind. This error had the impact of inflating the estimated cost of the pilot offshore wind project proposed in HB 2132.
  2. Incorrectly identifying certain gas-fired power plants as converting to Zero Emissions Facilities. These errors artificially increased modeled emissions within Illinois and may suppress the economic value of energy storage deployments.
  3. Incorrectly identified several nuclear plants for premature retirement. These errors resulted in increasing projected emissions for Illinois.

Comments to the Draft Study. The following comments are submitted for consideration by the IPA in its consideration and review of the Draft Study.

- General Comments. The Draft Study should include a consolidated table that lays out the costs and benefits that the IPA identifies in each of the separate analyses related to energy storage deployments. This addition will serve to clarify the aggregated economic impacts of energy storage deployments for policymakers and the public.

  Additionally, the Draft Study should present a concise digest of the data sources and values used in the development and completion of the analyses related to energy storage deployments. This will serve to demonstrate a heightened level of transparency and an opportunity for policymakers and market participants to better understand the assumptions underlying the IPA's analyses and conclusions.

- Generation Reliability and Resource Adequacy. The Draft Study states: "The proposed 7,500 MW of utility-scale energy storage would have an impact on generation and resource adequacy. In both 2030 LOLE would drop to 0.01 and in 2040 the LOLE would drop to zero. In other words, utility-scale energy storage could be expected to eliminate the likelihood of a loss of load event in 2040." This translates to energy storage deployments reducing outages by one day every ten years. While this is a definitive positive result, the Draft Study does not provide an estimate of the economic value of this improvement to system reliability.

  Grid operators recognize the economic value of avoiding power outages. MISO identifies the value of lost load (VOLL) as ranging between $3,500 to $23,000/MWh (LRTP Tranche 1 Portfolio Detailed Business Case, LRTP Workshop, March 29, 2022). MISO's VOLL rate indicates that avoiding just one-day of lost load in MISO Zone 4 (central and southern Illinois) would have a value of between $345 million and $2.3 billion (e.g., 98,630 MWh of average daily load * VOLL rate). The average annualized value of avoiding one day of outages every ten years in MISO Zone 4 would then be $35.5 to $230 million.

  PJM has not identified a VOLL range; however, the US Department of Energy and Lawrence Berkely Lab have developed the "Interruption Cost Estimate (ICE)" calculator. The ICE calculator allows electric reliability planners at utilities, government organizations or other entities to estimate the cost of service interruptions and the economic benefits associated with reliability improvements. Applying the ICE calculator to ComEd's load indicates that improving system reliability in Illinois to avoid a 1-day statewide outage every 10 years would have a value of over $29.7 billion, or an average annualized value of $297 million.

Credible public sources indicate that the annualized value of increasing grid reliability in Illinois to avoid 1 day of outages every 10 years can be as much as $520 million. This $520 million in annualized economic value exceeds the IPA's estimated annualized net costs of $298 million and $86.1 million for deploying utility-scale and distributed-scale energy storage in Illinois. Based on this, the IPA is encouraged to consider:

A. Including a statement in the Policy Study explicitly recognizing that the increased generation reliability resulting from the deployment of energy storage resources in Illinois will have a resulting economic benefit.

B. Including a range of potential value of the economic benefits resulting from the deployment of energy storage in Illinois similar to the values identified in these comments.

- Transmission Reliability and Grid Resiliency. The Draft Study states: "The analysis conducted for this policy study identified transmission upgrades that would be needed; however, these are only estimates and actual costs can only be determined by the completion of full interconnection studies by the applicable RTO. The results are expressed in total dollar cost to portray a magnitude of the investments that would be needed to allow for interconnection and then also on a dollars per megawatt basis which allows for the comparison of costs between diverse types of projects and proposals." The study then itemizes approximately $1.5 billion of estimated transmission system upgrade costs in Table 5-6 and 5-7 that are attributed to the deployment of energy storage in Illinois.

  The Draft Study's treatment of transmission system costs is challenging in two aspects. First, the Draft Study leaves the impression that deploying energy storage in Illinois carries significant new transmission costs but provides no transmission cost offsets which is inaccurate as multiple credible and public sources identify that energy storage can reduce congestion-related transmission costs (See: National Renewable Energy Laboratory, New York ISO, California ISO, PJM Interconnection). Second, the Draft Study fails to note that the transmission system upgrades resulting from energy storage deployments will be borne by energy storage project developers – not consumers. By not providing this context to the transmission cost issue, the Draft Study could lead policymakers and the public to believe that the costs cited are exogenous to the cost-benefit analysis of the energy storage deployment that is presented in the Draft Study.

  Based on this, the IPA is encouraged to consider:

  A. Excluding this section from the Draft Study as it does not provide a balanced interpretation of the costs and benefits that energy storage represents to transmission system operations, nor does it add value to the overall analysis of costs and benefits of energy storage deployment.

  B. Including an explicit statement acknowledging that the transmission costs cited would be borne by energy storage developers and not Illinois consumers, and that energy storage also delivers transmission cost savings.

- Impact on Electricity Costs. The Errata issued by the IPA states:

> "Further, the proposed utility-scale energy storage development would impact Illinois electricity prices in two ways: (i) based on the netting out an estimate of the revenue the projects would receive from capacity and energy sales, the study estimates a ~~$381~~ 298 million per year difference—this would be the annualized cost that would be supported by Illinois ratepayers through the purchase of energy storage credits from the projects by the utilities; and (ii) the storage projects would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $850.2 million over 20 years, or $25.5 million on an annualized basis in 2022 dollars. Deploying 1,000 MW of distributed energy storage would have an annualized cost of ~~$158.6~~ 86.1 million, while contributing $4.3 million in lowering wholesale electricity costs."

Unfortunately, the Draft Study provides neither the methodology nor the data used to calculate the net annual cost of "the purchase of energy storage credits from the projects by the utilities" as noted in item (i). The Associations encourage the IPA to release details of the methodology and data used in calculating these values. On a positive note, the Draft Study, its Appendices, Errata and supporting information do provide significant details concerning the data used to estimate the impact that energy storage deployment in Illinois will have on regional wholesale energy costs.

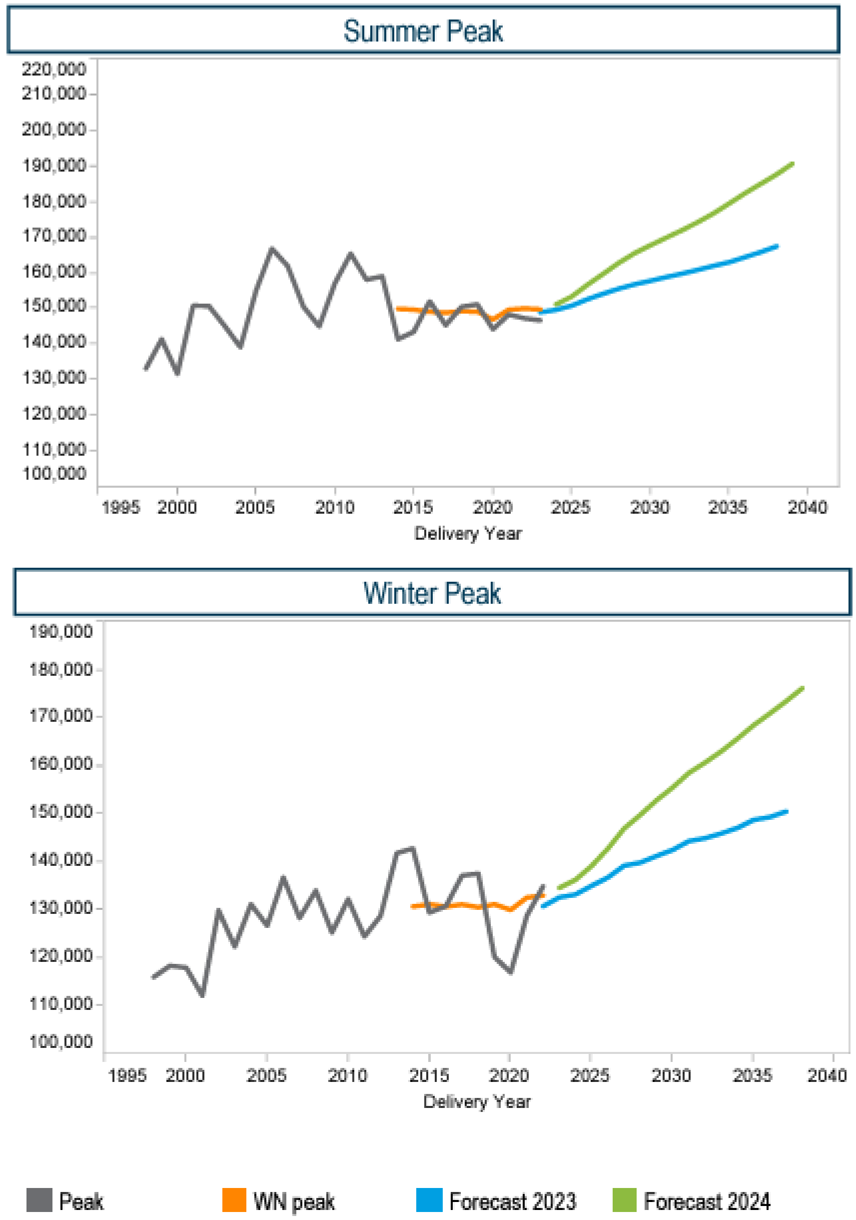
The IPA's consultant utilized the Aurora model to calculate the impacts on wholesale energy and capacity costs by considering "generation resources, costs, loads, operational characteristics, and environmental and other regulatory considerations." Certain assumptions used in the Aurora modeling do not reflect the current views of wholesale market operators, utilities, and other reputable and informed parties. Further, certain categories of impacts are not accounted for in the Aurora model. These outdated assumptions serve to suppress the value of energy storage deployments within the Draft Study.

Given the pivotal role that energy storage will play in meeting Illinois' energy policy goals, it is crucial that policymakers and the public are provided a clear understanding of the value of energy storage that is based on the most current data and is as comprehensive as possible. To that end, the Associations recommend that the IPA consider updating the following variables that inform the Draft Study's conclusions:

1. Projected Energy Consumption and Peak Demand. Future energy consumption and peak demand are key variables in establishing future energy and capacity costs. It appears that the Aurora model did not utilize summer and winter peak demand projections included in the PJM Load Forecast Report (January 2024).

   PJM updates the Load Forecast Report annually to reflect the most current view of winter and summer demand throughout the PJM footprint. Year to year changes in PJM's forecasts can be material. Figure 1 below conveys pronounced increases in both the summer and winter peak demands throughout the PJM service region. In models such as Aurora, major increases such as these would result in higher wholesale energy and capacity price projections. In turn, these higher price projections would reduce the net cost of the credits from energy storage assets; and increase the level of price suppression effect resulting from energy storage deployments and thereby increasing the annual value of energy storage in Illinois. Taken together, these impacts could improve the cost/benefit balance for energy storage deployments in Illinois by tens of millions of dollars annually.

FIGURE 1: PJM SUMMER AND WINTER PEAK LOAD FORECAST REPORT (2023 VS 2024)



Based on this, the IPA is encouraged to consider:

A. Updating the Aurora model to reflect the most recent energy and peak demand projections from PJM and MISO.

B. Adjusting the projected costs and benefits resulting from using the updated projections in any subsequent versions of the Policy Study.

2. Projected Fuel Costs. Projected fuel costs are another key variable in modeling future wholesale energy and capacity costs. Natural gas fuel price projections are the most impactful as natural gas represents the bulk of marginal power production throughout the eastern interconnection. As

such, low natural gas price projections would tend to suppress projected wholesale electricity prices in the Aurora model which would indicate a reduction in value for energy storage.

In the Draft Study, the Aurora model references the Energy Information Administration's Short Term Energy Outlook (September 2023) and the Annual Energy Outlook (March 2023) to identify price projections for Residential Fuel Oil, Distillate Fuel Oil, Coal, and Jet Fuel. However, the IPA's consultant chose to replace the natural gas price projections provided by the Energy Information Administration with a customized and confidential pricing source referenced as "S&P Capital IQ, Annual Energy Outlook" (MS Excel File "Fuel Prices," Tab 'Natural Gas').

The natural gas price projections from the "S&P Capital IQ, Annual Energy Outlook" that were used in the Aurora modeling are materially lower than the natural gas price projections issued by the Energy Information Administration in the 2023 Annual Energy Outlook Reference Case (Nominal Prices: Gas Price at Henry Hub (nom $/MMBtu). As noted in Table 2 above, the natural gas fuel price projections used in the Aurora modeling for the Draft Study are approximately 18% lower than those provided in the Energy Information Administration in the 2023 Annual Energy Outlook Reference case. Using lower natural gas fuel price projections would cause the Aurora model to project lower wholesale energy prices for northern Illinois. In turn, these lower

TABLE 2: DIFFERENCES IN NATURAL GAS PRICE PROJECTIONS

Year	PROJECTED HENRY HUB PRICES ($/MMBTU)		DIFFERENCES IN PROJECTIONS	
	Draft Study	**EIA Annual Energy Outlook, 2023**	**Annual Differential**	**Cumulative Differential**
2030	$3.91	$3.54	-9.5%	-9.5%
2031	$3.89	$3.78	-2.9%	-6.2%
2032	$3.87	$4.07	5.2%	1.1%
2033	$3.98	$4.44	11.7%	8.5%
2034	$4.08	$4.75	16.4%	14.0%
2035	$4.27	$5.02	17.7%	17.1%
2036	$4.36	$5.15	18.1%	17.9%
2037	$4.49	$5.33	18.8%	18.5%
2038	$4.71	$5.63	19.6%	19.2%
2039	$4.76	$5.64	18.4%	19.0%
2040	$5.02	$5.99	19.4%	19.0%
2041	$5.22	$6.26	19.9%	19.7%
2042	$5.32	$6.39	20.1%	20.0%
2043	$5.37	$6.43	19.7%	19.9%
2044	$5.48	$6.52	19.1%	19.4%
2045	$5.58	$6.66	19.4%	19.2%
2046	$5.69	$6.81	19.7%	19.5%
2047	$5.81	$6.91	19.0%	19.3%
2048	$5.95	$7.04	18.3%	18.6%
2049	$6.01	$7.08	17.9%	18.1%
2050	$6.11	$7.23	18.4%	18.1%
AVERAGE	**$4.95**	**$5.75**		

wholesale price projections would serve to increase the net cost of the credits from energy storage assets; and decrease the level of price suppression effect resulting from energy storage deployments thereby decreasing the annual value of energy storage in Illinois.

Based on this, the IPA is encouraged to consider:

A. **Updating the Aurora model to reflect the natural gas price projections as presented by the Energy Information Administration in the Annual Energy Outlook for 2023.**

B. **Adjusting the projected costs and benefits resulting from using the natural gas price projections from the Energy Information Administration in any subsequent versions of the Policy Study.**

3. Capacity Cost Projections. Capacity charges represent a major portion of the total wholesale electricity costs in Illinois. Capacity charges are used to compensate owners of generating capacity or demand response resources to ensure their ability to dispatch power to ensure grid reliability in a future period (usually 1-3 years). Capacity charges in Illinois are set through auction processes managed by PJM and MISO and reflect the relative balance of generating capacity and peak demand within the region. Capacity auctions can result in unique prices within specific zones within PJM and MISO and are subject to a maximum price (e.g., the Cost of New Entry, or "CONE").

   The capacity cost projections included in the Draft Study for PJM indicate that capacity prices within the ComEd Zone will be equal to the capacity prices for all of PJM. This pattern contradicts the historical capacity pricing patterns within PJM and ignores FERC's recent approval of changes to the CONE calculation methodology for the ComEd Zone.

   Historically, the ComEd Zone has received a capacity rate that is higher than the capacity rate realized by the rest of the western region of PJM ("RTO"). Table 3 conveys how five of the last six capacity auctions held by PJM yielded a higher capacity rate for the ComEd Zone than the RTO by an annualized average of approximately 60% (see columns A, B, C). As shown, when the annual difference between the capacity rate for the ComEd Zone and the RTO rate is applied against a nominal 22,000 MW of required capacity for the ComEd Zone, then the average annualized value of the difference in capacity pricing between the ComEd Zone and the RTO is calculated to be approximately $450 million.

TABLE 3: DIFFERENTIALS BETWEEN CAPACITY PRICES FOR COMED ZONE AND PJM RTO

Year	HISTORICAL BASE CAPACITY PRICES ($/MW-DAY)					
	RTO CLEARING PRICE ($/MW-Day)	COMED CLEARING PRICE ($/MW-Day)	DIFFERENTIAL ($/MW-Day)	ESTIMATED CAPACITY REQUIRED (MW)	ANNUAL DAYS	CAPACITY COST DIFFERENCE
	A	B	C=B-A	D	E	F=C*D*E
2018-2019	$164.77	$215.00	$50.23	22,000	365	$403,346,900
2019-2020	$100.00	$202.77	$102.77	22,000	365	$825,243,100
2020-2021	$76.53	$188.12	$111.59	22,000	365	$896,067,700
2021-2022	$140.00	$195.55	$55.55	22,000	365	$446,066,500
2022-2023	$50.00	$68.96	$18.96	22,000	365	$152,248,800
2023-2024	$34.13	$34.13	$0.00	22,000	365	$0
AVERAGE / TOTAL	**$94.24**	**$150.76**	**$56.52**	**22,000**	**365**	**$453,828,833**

Additionally, the Draft Study does not consider how CONE will be calculated for the ComEd Zone in future periods. Historically, CONE has been calculated to reflect the marginal revenue necessary to support the deployment and operation of a combined cycle natural gas plant in a region to provide additional capacity in support of grid reliability. An essential element of calculating CONE involves amortizing the capital cost of the modeled power plant over a 20-year period. However, due to the requirements of the Climate and Equitable Jobs Act, all new fossil fuel power plants must achieve zero emissions by 2045. Because no currently available technologies can reduce natural gas power plant's emissions to zero, it is assumed that fossil fuel power plants in Illinois will cease operations at or before 2045. As such, using an amortization term of 20 years to calculate CONE has been determined to be unrealistic by PJM and FERC. To remedy this issue, FERC has ordered PJM to adjust its CONE calculation to include shorter amortization schedules. The net result of this will be an elevated CONE for the ComEd Zone that will be applied to all capacity transactions when the combination of local and imported generating capacity cannot meet the ComEd Zone capacity requirements.

The capacity rates for the ComEd Zone used in the Draft Study are materially lower than one would assume. At the very least, the capacity rates cited by the IPA's consultant should be increased over the average projected PJM capacity rate to account for the historically higher capacity rates recorded within the ComEd Zone. Additionally, the application of unique and higher CONE calculations for the ComEd Zone justifies additional analysis to determine whether the new CONE rates may be applied at any time over the 20-year term of the study. The artificially lower capacity price projections used in the Draft Study contribute to lower total wholesale energy price projections for northern Illinois which result in an increase in the net cost of the credits from energy storage assets; and a decrease in the price suppression effect resulting from energy storage deployments. In sum, the artificially low capacity cost projections cause the Draft Study to undervalue energy storage in Illinois.

Based on this, the IPA is urged to consider:

A. **Updating the Aurora model to reflect a historically based price escalator to the ComEd Zone capacity prices.**
B. **Modeling the specific application of the new CONE ruling from FERC for the ComEd Zone.**
C. **Adjusting the projected costs and benefits resulting from correcting ComEd Zone capacity price and the application of the FERC-approved CONE calculation for the ComEd Zone.**

4. Fossil Fuel Power Plant Retirement Schedule. The number and capacity of operating power plants is another key variable in modeling future wholesale energy and capacity costs. The assumptions regarding power plant retirements and deployments dictate the amount of energy supply and capacity that is available to meet regional energy needs. Lower amounts of power plant capacity cause higher energy and capacity prices. Questionable modeling assumptions artificially increase the amount of available power generation and capacity in the Aurora which reduces the value of energy storage.

   The data file provided by the IPA's consultant named "Resource Addition and Retirement" specifies that 8,500 MW of Zero Emissions Fuel ("ZEF") generating units will appear in PJM and MISO in 2045. The Draft Study states, "Given that storage is one of the policy options tested in but-for cases, the modeling team elected to "repower" about 8.5 GW of fossil capacity retired under CEJA to Zero Emissions Fuel ("ZEF") units, the bulk of which is switched over in 2045." The Draft Study does not describe the ZEF technologies, their ownership, financing, operation, or the likelihood of their appearance in 2045. While all parties appreciate that innovative technologies can and do enter the marketplace, the scale and timing of the assumed ZEF technology lacks credibility.

   Introducing an arbitrary volume of 8,500 MW of ZEF technologies into the Aurora model increases the amount of available energy generation and capacity in the PJM and MISO markets. Increasing the amount of generating capacity in the Aurora model reduces wholesale energy price projections for PJM and MISO. In the Draft Study, these lower wholesale energy price projections result in higher net cost for credits from energy storage assets; and decreased levels of annual price suppression resulting from energy storage deployments in Illinois. Taken together, these impacts may be suppressing the projected overall value of energy storage in the Draft Study by as much as hundreds of millions of dollars a year over the term of the study.

   Based on this, the Associations encourage the IPA to consider:

   A. **Updating the Aurora model to remove the arbitrary ZEF volumes from the Aurora model.**
   B. **Adjusting the projected costs and benefits resulting from removing ZEF volumes from the Aurora model**

5. **Ancillaries.** The IPA's consultants have indicated that the Aurora modeling did not consider the value that energy storage deployments would provide in ancillary services. This is concerning insofar as the PJM Independent Market Monitor reports that ancillary service costs amount to an average of $1.30/MWh of load in 2023 (or approximately $110 million a year for ComEd customers) and the MISO Independent Market Monitor reports an average ancillary cost of approximately $15/MWh (roughly $525 million a year for Ameren Illinois customers). States including California and New York as well as other credible organizations including Sandia National Lab and National Renewable Energy Lab all identify reduced ancillary charges as a primary benefit

of energy storage. Considering that the need for ancillary services will increase over time as the regional grids transition to more distributed resources, it would be incomplete for a large market such as Illinois to not apply at least a nominal value to the benefit that energy storage can deliver to ancillary services markets.

Ignoring the potential reduction in ancillary services charges that would result from the deployment of energy storage in Illinois suppresses the economic benefits attributable to energy storage. Not accounting for this value effectively increases energy price projections in the Aurora model, which in turn results in higher net cost for credits from energy storage assets; and decreased annual price suppression effect resulting from energy storage deployments in Illinois. Taken together, these impacts would increase the projected overall value of energy storage in the Draft Study by as much as tens of millions of dollars a year.

Based on this, the IPA is urged to consider:

A. Updating the Draft Study to identify a potential range of values for the reduction of ancillary costs resulting from energy storage deployments in Illinois.

6. **Full Value of Distributed Resources.** The IPA's consultants indicated that the modeling did not consider the multiple value streams delivered by distributed energy storage systems. Considering that legislation contemplates one gigawatt of distributed energy storage resources, arriving at an estimate of the potential values is appropriate and expected.

The benefits of behind the meter storage vary based on configuration, size, and location. However, credible parties and regulatory processes have identified that both retail and wholesale value is gained with distributed energy storage resources. The Illinois Commerce Commission is conducting an ongoing Investigation into the Value of Distributed Energy Resources, including distributed energy storage, that involves a review of best practices in calculating the value of distributed energy resource benefits. Examples of value categories include peak energy cost savings, emissions reductions, enhanced resilience and reliability, reduced line losses, reduced coincidental capacity requirements, reduced ancillary services, enhanced transmission capacity, and increased distribution capacity.

Other states have successfully calculated the value of distributed energy storage in diverse ways. In New York, NYSERDA has recommended that all utilities compensate distributed energy storage according to the model applied by Consolidated Edison through its Rider Q tariff. Rider Q identifies the value of distributed energy storage as ranging between 8%-17% of energy and demand charges.

Neglecting to address the potential benefits of distributed energy storage in Illinois effectively reduces the economic benefits reported in the Draft Study. In turn, this results in higher net cost for credits from energy storage assets; and decreased annual price suppression effect resulting from energy storage deployments in Illinois. In sum, including distribution system benefits resulting from distributed energy storage in the Draft Study would increase the projected value of energy storage millions of dollars a year.

Based on this, the IPA is encouraged to consider:

B. Updating the Draft Study to identify a potential range of values attributable to distribution systems resulting from distributed energy storage deployments in Illinois.

Conclusions. As noted, the Policy Study is intended to aid policymakers and stakeholders develop policies that will provide Illinois consumers with access to dependable, affordable, and sustainable energy. To accomplish this, the Policy Study should be complete and clear.

The above comments identify how the Draft Report repeatedly failed to identify or correctly estimated hundreds of millions of dollars of annualized cost benefits resulting from the deployment of energy storage in Illinois. Collectively, this approach is contrary to the findings of DOE, national labs, RTOs and other analyses regarding the impact of energy storage. The Associations encourage the IPA to revisit and consider these comments and remain available to support the IPA in the study process at any time.

In light of the comments, corrections, and recommendations provided above, the Associations request that the IPA consider including in the Final Study a specific recommendation that the state adopt an energy storage procurement policy that aligns with the framework of proposed legislation.