Jackson County Community Solar Modeling Results

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Context

- The U.S. Department of Energy's Communities LEAP (Local Energy Action Program) pilot supports community-driven action plans for clean energy-related economic development.
- Jackson County, Illinois is one of 24 selected Communities LEAP communities. They applied to the pilot for assistance developing their clean energy transition road map.
- After an extensive scoping process, the Jackson County community coalition prioritized a community solar road map for customized, high-quality technical assistance

Executive Summary

- At the request of the Jackson County community coalition, NREL completed a technical and financial modeling exercise to determine the potential for developing community solar in the region, with the following findings:
  - The current policy and economic environment is advantageous to the deployment and growth of community solar in Illinois.
  - Illinois's Solar For All (Ill SFA) program is well designed to reduce the energy burden of low- and moderate-income (LMI) households that subscribe to community solar in the state, including in Jackson County.
  - Across all scenarios modeled, including limited and generous project incentives, the economics are advantageous to both the project owner and its subscribers.
  - The modeling presented is only one of the first steps in deploying community solar and puts Jackson County in a good position to pursue next steps, including:
    - Refining project economics with potential project developers
    - Working with local utilities and policymakers to increase access to all desired Jackson County residents
    - Educating and engaging community members to increase interest and identify potential subscribers.

Key Findings

- Community solar development is economically viable in Jackson County within Ameren's service territory through favorable structures (such as net metering) that can reduce subscribers’ energy costs and increase access to renewable energy under the current Ill SFA program.
- All potential project designs and scenarios modeled provided the project developer and subscribers with a net positive economic outcome, meaning that the market is well suited to supporting a community solar project.
- The Ill SFA program and enabling state legislation creates an environment that supports favorable economics for community solar development, particularly projects that include LMI subscribers, and reduces developer and subscriber risks via well-regulated consumer protection rules, project verification protocols, and a history of successful community solar projects.
- The notable hurdles left to address are refining project economics now that viability has been proven, expanding access to community solar projects for more electricity consumers by implementing a community solar program with favorable structures in the electric cooperative (COOP) territory (not controlled by Ameren) of Jackson County, and gathering community support by engaging potential subscribers to help educate and reduce the friction of subscriber acquisition by building trust in the community.

Next Steps

- Jackson County can take the findings from this modeling and move forward with some thoughtful next steps:
  - Refine the community's goals of community solar, including which (if not both) utility territories in which they would like a project developed.
  - Engage community organizations and trusted partners to increase knowledge and interest in community solar using readily available market and education materials:
    - See the National Community Solar Partnership resources for examples.
  - Engage in discussion with potential project developer/owners (e.g., using a request for information) and work toward an investment-grade analysis.
  - Further engage key project stakeholders, including potential site owners, utility staff, Ill SFA program staff, financiers, and more:
    - Work with stakeholders to assign responsibility and next steps to ensure accountability.

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Glossary

- **Community Solar (CS):** Any solar project or purchasing program, within a geographic area, in which the benefits of a solar project flow to multiple customers such as individuals, businesses, nonprofits, and other groups.
- **Subscribing Customer:** The individual or household representative that claims membership in the CS project.
- **Project Developer:** The entity, which undertakes the responsibility of building and owning the CS project.
- **Subscription Rate:** Money paid by a subscribing customer to the project developer for their respective portion of the solar project.
- **Subscription Credit:** Money credited to a subscribing customer, by the electric utility, via their electricity bill.
- **Subscription Savings:** The net difference between the subscription rate and subscription credit.
- **Bill Savings:** The net reduction (+ or -) of the subscribing customers electric bill after subscription credits are applied and the subscription rate is accounted for.
- **Subscriber Class:** The rate class that the subscribing customer belongs to which dictates Subscription Credit they will receive.
- **Anchor Tenant**: Large electric customers that subscribe to a significant portion of a community solar array (e.g. a municipal building, industrial facility, large retail store).
- **Net Present Value (NPV):** The present value of a cash flow, which is dependent on the interval of time and discount rate, and accounts for the time value of money to provide a comparable basis for evaluating projects.
  - All NPVs presented are from the perspective of the project developer/financier.
- **Internal Rate of Return (IRR):** A metric used in financial analysis to estimate the profitability of potential investments and one that makes the NPV of all discounted cash flows equal to zero.
  - All IRRs presented are from the perspective of the project developer/financier.
- **Capital Expense (CAPEX): E**xpenses associated with the purchase of equipment and services for the project's construction.

Acronyms

- **C-LEAP:** Communities Local Energy Action Program
- **NREL:** National Renewable Energy Laboratory
- **Ill SAF:** Illinois Solar for All
- **LMI:** Low to Moderate Income
- **kW:** Kilowatt
- **kWac:** Kilowatt alternating current
- **kWdc:** Kilowatt direct current
- **kWh:** Kilowatt hour
- **REC:** Renewal Energy Certificate
- **GCR:** Ground Coverage Ratio
- **SAM:** System Advisor Model
- **ITC:** Investment Tax Credit
- **IRA:** Inflation Reduction Act
- **O&M:** Operations and Maintenance
- **CAPEX:** Capital Expense
- **NPV:** Net Present Value

Background

Request

- The Jackson County community coalition requested technical assistance to support their community solar pathway.
- Specifically, they requested impact assessment, techno-economic assessment, and economic opportunity assessment based on the large renter population and other unique demographics of Jackson County.
- The technical assistance provided by NREL aims to better inform community stakeholders on what community solar solutions may look like in Jackson County, help define the financial and economic benefits, and provide technical data to support a community solar pathway within their Clean Energy Transition Road Map.
- Based on the request, the technical assistance took the form of modeling project performance and economics in NREL's System Advisor Model (SAM) to determine the range of deployable project options and savings to subscribers and project owner.
  - SAM is a model designed to investigate questions about the technical, economic, and financial feasibility of renewable energy projects to facilitate informed decision making.

Techno-Economic Modeling

- NREL used SAM to model six scenarios.
- Three project nameplate capacities modeled: 200 kW, 500 kW, 5,000 kW.
- For each project size, modeled two economic variations, a best case and worst case:
    - Cases used to identify a potential project cost upper and lower range.

	Best Financial	Worst Financial
200 kW	1A	1B
500 kW	2A	2B
5,000 kW	3A	3B

Modeling

- Modeling outputs include:
  - Overall project economics
  - How financial variables affect a project's economic viability
  - The subscriber savings and bill perspective
  - Subscriber class (e.g., residential or anchor) impacts on the project
  - Utility territory of the project's location and the impact on project and subscriber economics
  - Assumptions and potential modeling errors.
- The modeling approach and assumptions presented in the following slides were discussed and confirmed with community coalition representatives.

Methodology

Modeling Scenario Basis

- The six base scenarios were modeled based on subscribers and a project located in the Ameren territory, because an existing rate structure and net metering process is in place for Ameren Illinois.
- The project modeled was for qualified LMI residential subscribers under the Ill SFA program.
- The project was modeled as qualifying for the Ill SFA program, including receiving financial Renewable Energy Credit (REC) payments.
- The project was assumed to receive a range of Investment Tax Credit (ITC) payments, depending on the scenario, through the direct pay process enabled by the Inflation Reduction Act (IRA).
    - Direct pay is the ability for tax-exempt and governmental entities to receive a payment equal to the full value of tax credits they would receive if they were taxable.

SAM Modeling Inputs

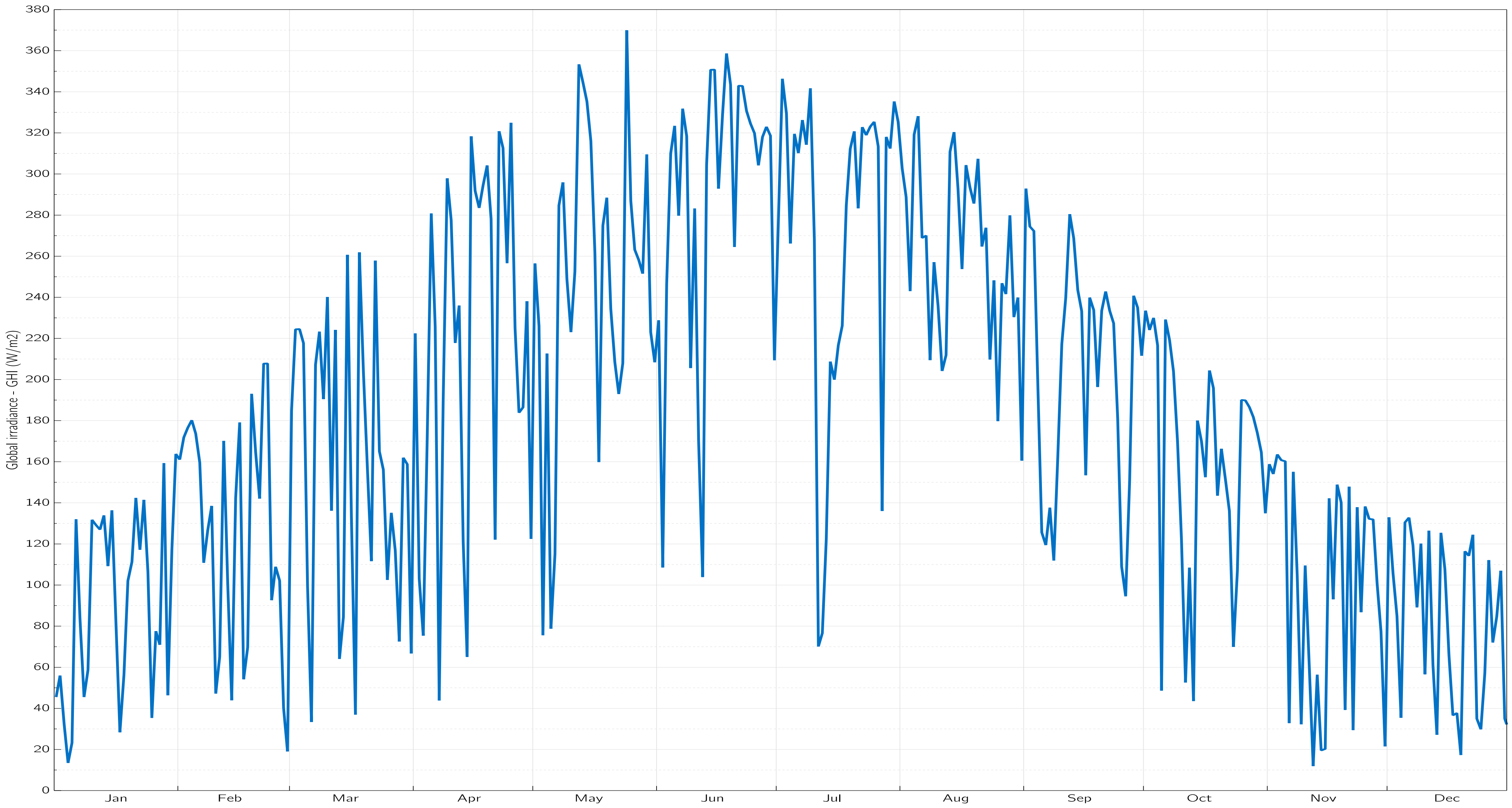
- The modeling inputs outlined below and in the following slides were developed and agreed upon through a process with the Jackson County Coalition and engineering best practices to ensure a valid and accurate model.
- The modeling categories for which inputs are required by SAM were:

  - Location and Resources
  - System Design
  - Lifetime and Degradation
  - Installation Costs
  - Operating Costs
  - Community Solar
  - Financial Parameters
  - Incentives
  - Depreciation.

Location and Resources

- Used a generic location for the most populous city in the county, as sites may vary across the region:
  - 37.7273, -89.2158
  - Downtown Carbondale, Illinois.
- Used a typical meteorological year:
  - Pulled from National Solar Radiation Database and used their logic for solar insolation
  - 4 km x 4 km area data granularity.

Weather Data: Daily Global Horizontal Irradiance



System Design

- Project capacities: 200 kWac, 500 kWac, and 5,000 kWac:
  - Determined to match relevant and representative project sizes with readily available cost data.
- DC:AC ratio is 1.25 for 200-/500-kWac systems (250 kWdc and 625 kWdc) and 1.35 for 5-MWac system (6.75 MWdc):
  - Based on data from NREL and Lawrence Berkley National Laboratory, respectively:
    - This includes data from NREL's Annual Technology Baseline.
- All project sizes were modeled as fixed tilt for direct comparison relative to system production.
- Systems were assumed to face due south (azimuth = 180°), with tilt optimized from parametric runs for max generation and a variable ground coverage ratio (GCR) based on roof or ground mount.
- For rooftop systems (200 kWac), the GCR was left at default of 0.3, and for the ground-mount systems (500 kWac and 5 MWac), the GCR was set at 0.4:
  - The 0.4 GCR used the lower value of typical designs, assuming no land limitations, as it provided higher system output.

Note: While land area was not a model input, based on the above system parameters, the model estimated the ground-mount systems would require an area of 3.048 acres for the 500-kW system and 32.921 acres for the 5-MW system.

Lifetime and Degradation

- System losses were left as the default in SAM: 14.08%.
- Annual AC degradation was set at 0.5%/year, the SAM default.
- An annual degradation of 0.5%/year was also the standard annual production degradation rate in Ill SFA program rules.

Installation Costs

- Cost data was sourced from NREL and Lawrence Berkeley National Laboratory for the different size systems.
- NREL's Annual Technology Baseline and its underlying data sources were used to define cost components for the 200-kW and 500-kW systems.
- Lawrence Berkeley National Laboratory's Utility-Scale Solar publication was used for the 5-MW system, rather than NREL's ATB for utility scale, due to increased project size granularity.
- 200 kWac/250 kWdc:
  - $1.84/Wdc used for reference, after removal of tax costs $1.79/Wdc was modeled.
- 500 kW:
  - $1.94/Wdc used for reference, after removal of tax costs $1.90/Wdc was modeled. Increase in cost is due to shift to ground mount from roof-mount system.
- 5,000 kW:
  - $1.14/Wdc, used for reference and matched for modeling after updating some component costs using NREL values.

Operating Costs

- Operations and maintenance (O&M) costs were pulled from NREL studies for the relevant size systems:
  - Commercial (200 kW and 500 kW): $19/kWdc-yr
  - Small utility ground mount: $17/kWdc-yr:
    - Used a utility rate averaged between market data for commercial ground and utility ground mount (https://www.nrel.gov/docs/fy22osti/83586.pdf).
- Lease costs are a highly variable value that can be hard to define because they vary by region, land use alternatives, and contract negotiations:
  - Commercial-sized systems (200 kW and 500 kW): the lease cost was assumed to be covered in the O&M costs (as noted in NREL cost models).
  - For simple comparison, the utility model was run with no lease cost and a sensitivity was performed to see the impact lease costs would have on project economics.

Community Solar: Project Design

Two different project/program structures were discussed: an LMI residential-only program (modeled) and an LMI residential program with a nonprofit anchor (not modeled).

- The base model considered a single subscriber class consisting of LMI residential subscribers only:
  - An LMI-only project met Ill SFA requirements if it also had no upfront fees and the subscription costs were not more than 50% of the value generated for subscribers (e.g., savings).
- An alternative model, discussed but not modeled, was the cost benefit/burden of having a nonprofit anchor and LMI subscribers:
  - A qualifying nonprofit anchor tenant allowed the remainder of the project to remain in the SFA program, but the anchor tenant was limited to 40% of the project capacity. That portion of the project was compensated at the Illinois Shines REC rates (for 15 years), rather than the Ill SFA REC rates.
  - Ill SFA stated that if the ITC was obtained, the anchor tenant must receive 65% savings rather than 50% savings.
  - LMI subscriber class must make up minimum of 50% program at the end of the first year, and all other SFA program details applied to those subscribers.
- See Ill SFA Rules for additional information.

Community Solar: Project Design (cont.)

- LMI subscribers are compensated (credited) at the ”Price to Compare” for Ameren Illinois Customers:
  - The current energy price to compare is $0.07877/kWh and was used for modeling.
- Ill SFA requires subscribers to receive 50% bill savings; therefore, the subscriber subscription rate was set at 50% of the credit rate (which is the energy “price to compare” as noted above). A subscription rate of $0.039385/kWh was used for modeling
  - The subscription rate and credit rate described both increased with the inflation rate over the life of the project.
- Program administration costs included upfront costs as well as ongoing costs to manage and market a project to subscribers. These costs can vary a great deal based on the multiple factors related to billing systems, subscriber turnover rate, and ease of access to an interested and eligible subscriber pool.
  - Data from reports produced by Vote Solar and Wood Mackenzie provide a range of costs for subscriber acquisition and ongoing subscriber billing and subscriber management.
  - According to these reports, subscriber acquisition costs can range from $51/kW up to $250/kW, with Wood Mackenzie reporting that LMI subscribers acquisition cost is $175/kW on average (Using data from Quarter 2 of 2023).
  - The Vote Solar report from 2018 shows ongoing billing and subscriber management (including subscriber replacement costs) generally ranges between $120/kW and $350/kW. It is unclear whether the ongoing cost is normalized to an upfront cost or as an annual cost.
  - The Vote Solar report also uses a cost of $20/kW-yr for ongoing management in modeling, which is far lower than $120/kW or $350/kW.
- For modeling purposes, a one-time upfront cost of $175/kW was used, and an ongoing cost of $30/kW-yr was used:
  - Sensitivities were run for upfront and ongoing costs to show the tipping point of net present value (NPV) relative to admin costs.

Financial Parameters

- Income and sales tax assumed to be 0% based on nonprofit funding status.
- Property tax rate: assumed to be 0%.
- Insurance: assumed to be included in O&M.
- Inflation rate: 2.5%/yr.
- Real discount rate: 2.439%/yr:
  - Goal of matching Interest rate (for tax-exempt financing using bond rate, see below) with nominal discount rate; therefore, at 2.5% for inflation and a 2.439% real discount rate = a 5% nominal discount rate.
- Nominal discount rate: 5%/yr, set to match annual interest rate.
- Debt percentage: 100% debt (nonprofits do not have cash on hand).
- Debt length: 25 years.
- Interest rate: 5% based on Illinois 30-year treasury/municipal bond rate (https://capitalmarkets.illinois.gov/content/dam/soi/en/web/capitalmarkets/documents/official-statements/2023/State%20of%20Illinois%20Series%20of%20May%202023ABCD%20Official%20Statement.pdf). .
- Closing costs: 2.5%, based on information given by Jackson County Community Coalition members.

Incentives and Depreciation

- Tax incentives were modeled as A or B scenarios:
  - ”A” scenarios represented a financially advantageous scenario.
    - Direct pay with base 30% ITC credit obtained in addition to a 30% bonus/adder obtained.*
      - Domestic content, energy community, and/or LMI/Tribal. Jackson county qualified under the energy community definition.**
    - Total 60% ITC modeled as an investment-based incentive in SAM.
  - “B” scenarios represented a less financially advantageous scenario.
    - Direct pay with 30% base ITC and no additional adders modeled as investment-based incentive in SAM.
  - A and B scenarios delineated the upper and lower bounds of likely possible financial situations; numerous factors such as market conditions, economic trends, politics, and more dictated the reality of financial scenario achieved.
- Ill SFA (for Ill Shines, see appendix) REC payments were included as a production-based incentive.
  - SFA project received a 20-year REC contract using the most recent SFA REC price data:
    - 100-200 kW: $107.95/MWh
    - 200-500 kW: $102.49/MWh
    - 2,000-5,000 kW: $74.60/MWh.
- Depreciation (including MACRS, or Modified Accelerated Cost Recovery System) assumed was not included, as no property tax liability exists.

* See IRS for more ITC guidance: https://www.irs.gov/inflation-reduction-act-of-2022.
** Energy Community delineation tool: https://energycommunities.gov/energy-community-tax-credit-bonus/.

Model Scenario Inputs

<table>
<tr><th>Scenario</th><th>Tilt</th><th>GCR</th><th>CAPEX</th><th>O&M</th><th>ITC</th><th>REC</th></tr>
<tr><td>1A</td><td>33</td><td>0.3/NA</td><td>$1.79/Wdc</td><td rowspan="2">$19/kW-yr</td><td rowspan="3">60%</td><td>$107.95/MWh</td></tr>
<tr><td>2A</td><td rowspan="2">29</td><td rowspan="2">0.4</td><td>$1.90/Wdc</td><td>$102.49/MWh</td></tr>
<tr><td>3A</td><td>$1.14/Wdc</td><td>$17/kW-yr</td><td>$74.60/MWh</td></tr>
<tr><td>1B</td><td>33</td><td>0.3/NA</td><td>$1.79/Wdc</td><td rowspan="2">$19/kW-yr</td><td rowspan="3">30%</td><td>$107.95/MWh</td></tr>
<tr><td>2B</td><td rowspan="2">29</td><td rowspan="2">0.4</td><td>$1.90/Wdc</td><td>$102.49/MWh</td></tr>
<tr><td>3B</td><td>$1.14/Wdc</td><td>$17/kW-yr</td><td>$74.60/MWh</td></tr>
</table>

Results and Findings

Results

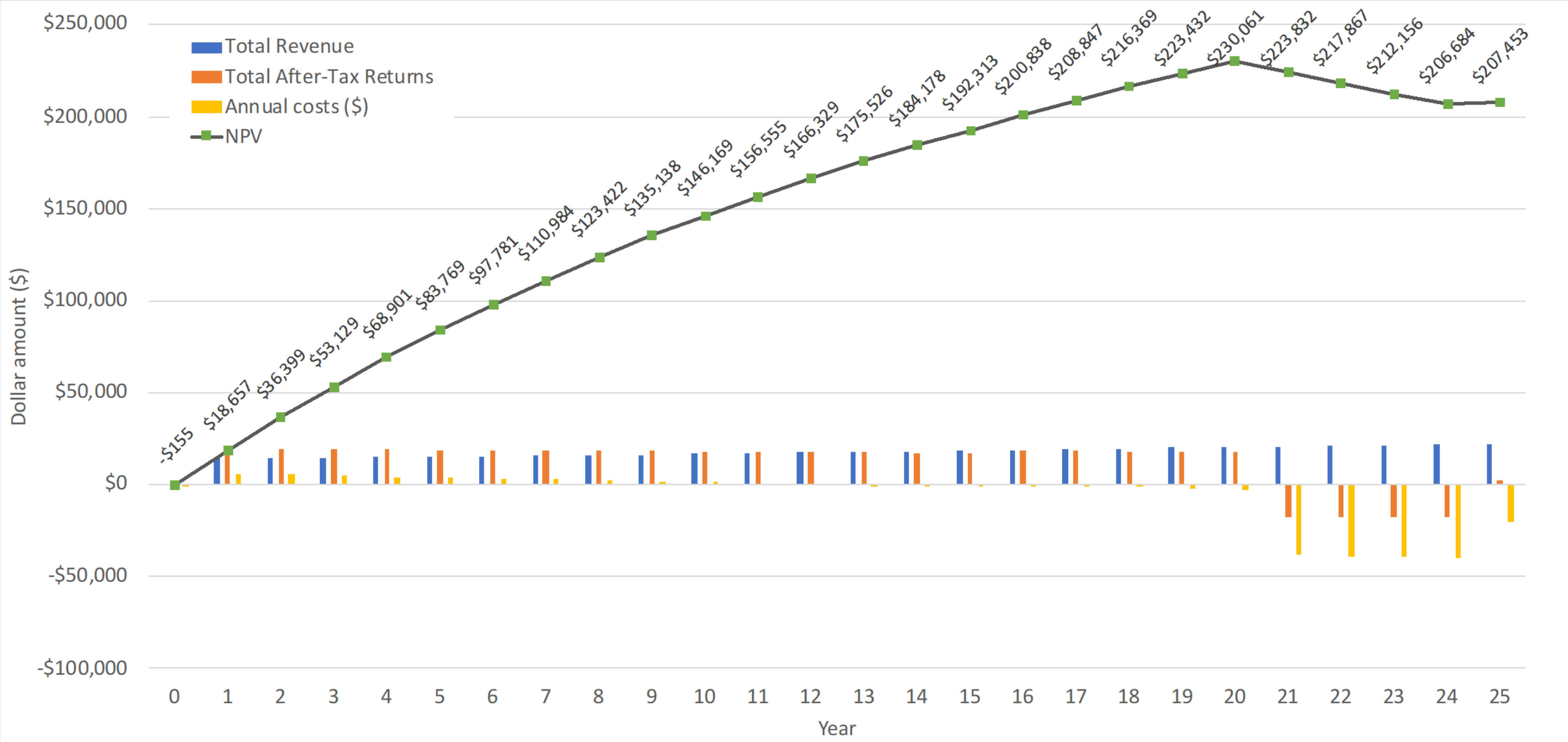
- Documented total capital expenditure (CAPEX), value of the ITC received, and project NPV.
- Plotted cash flows and NPV over the 25 years of each project’s life:
  - Scenarios 1A and 1B are shown in the following slides for comparison
  - The remainder of the graphs can be found in the appendix for reference.
- The base scenarios are followed by sensitivity model results, then a discussion of relevant findings.

Results Summary

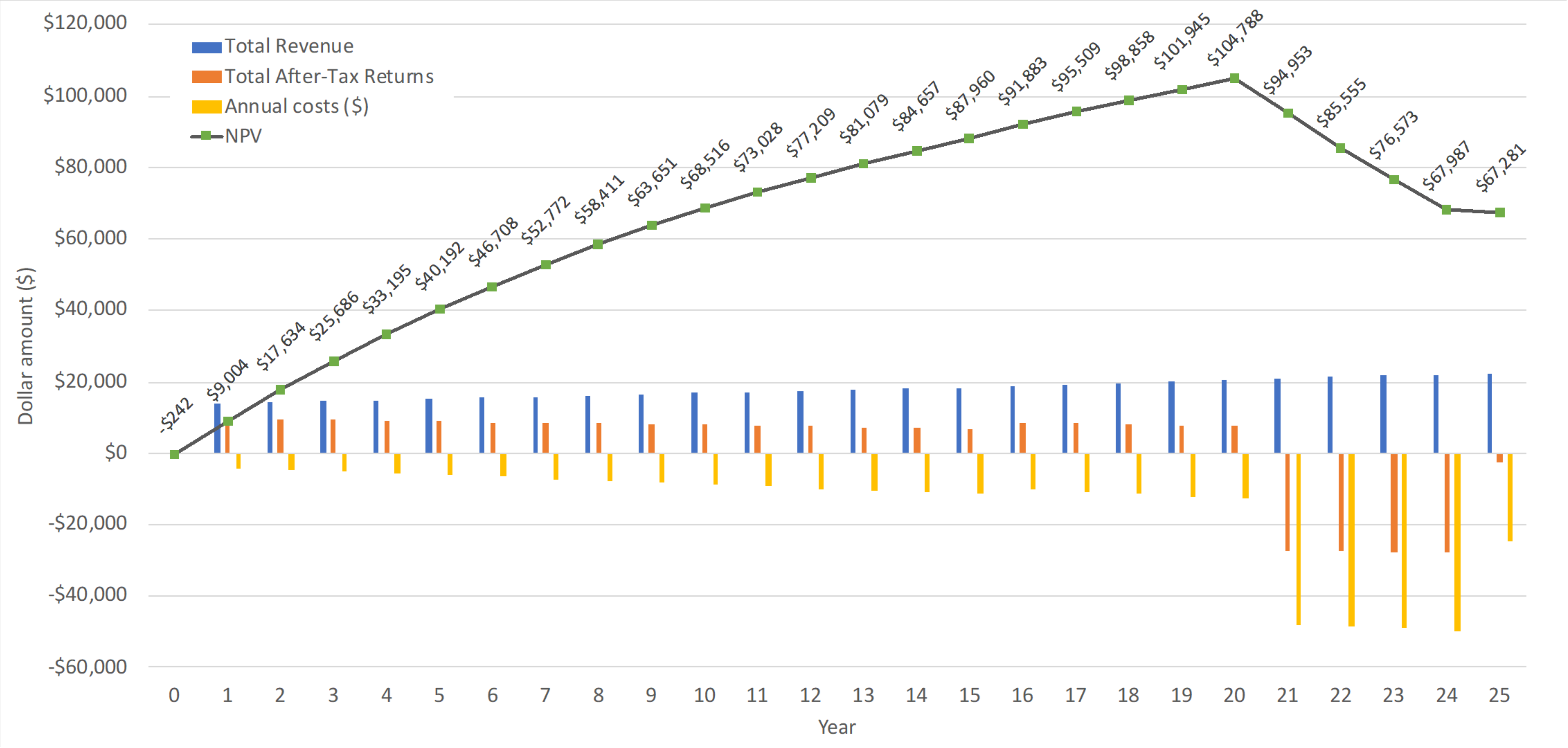
Scenario	Year 1 Output (kWh)	ITC Value	Gross CAPEX	Net CAPEX	NPV	Levelized Cost of Energy (¢/kWh)
1A	355,121	$267,876	$521,723	$253,847	$207,453	9.64
2A	879,873	$712,740	$1,379,621	$666,881	$413,721	9.99
3A	9,461,777	$4,634,880	$9,534,620	$4,899,740	$3,734,515	8.10
1B	355,121	$133,938	$530,339	$396,401	$67,281	12.52
2B	879,873	$356,370	$1,402,545	$1,046,175	$40,766	13.09
3B	9,461,777	$2,317,440	$9,683,695	$7,366,255	$1,309,225	9.98

- The levelized cost of energy is the total project life cycle cost expressed in cents per kilowatt-hour of electricity delivered to the grid by the system over its life.
- The formula used to calculate levelized cost of energy was the sum of the CAPEX after ITC payment, plus the annual operation costs discounted to present terms, divided by the annual generation (kWh) discounted to present terms.

1A Results

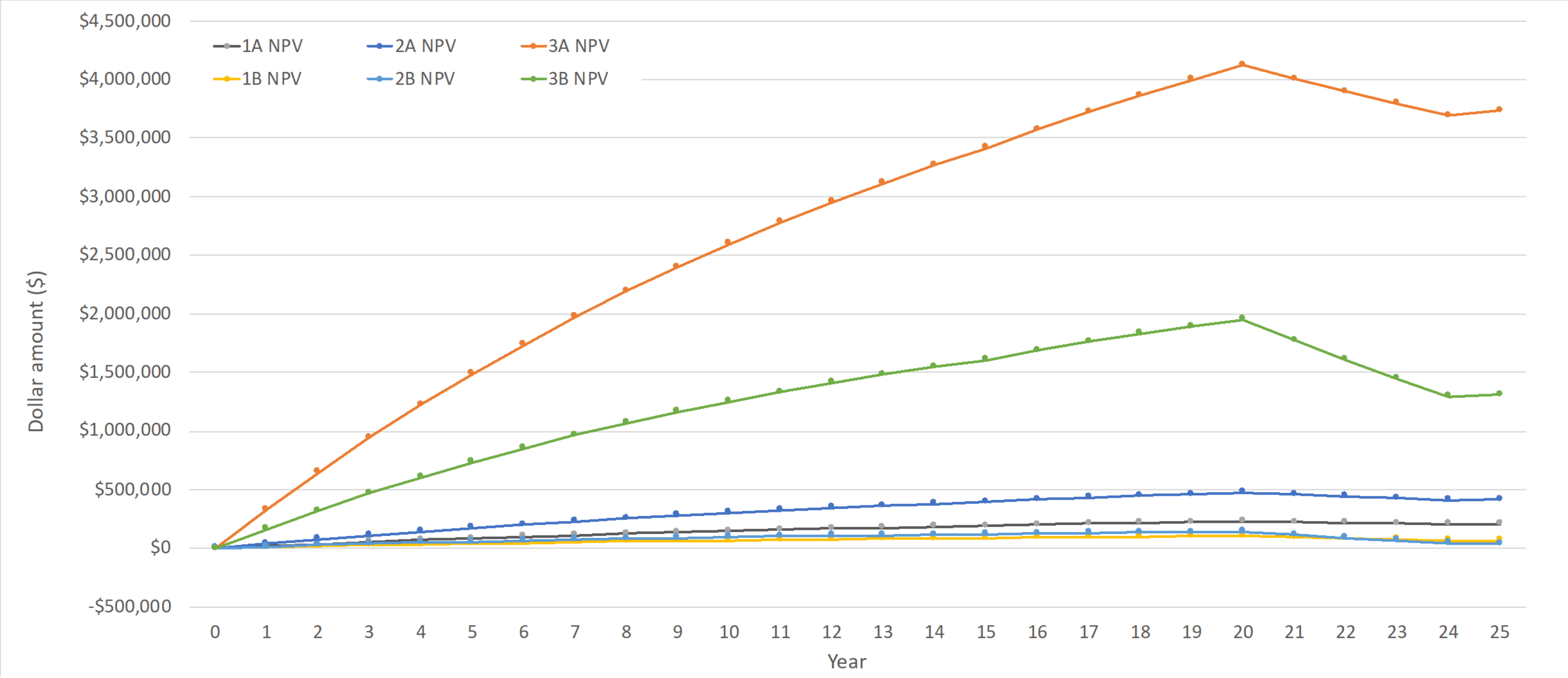

Total Revenue
Total After-Tax Returns
Annual costs ($)
NPV
$250,000
$200,000
$150,000
$100,000
$50,000
$0
-$50,000
-$100,000
Dollar amount ($)
Year
-$155
$18,657
$36,399
$53,129
$68,901
$83,769
$97,781
$110,984
$123,422
$135,138
$146,169
$156,555
$166,329
$175,526
$184,178
$192,313
$200,838
$208,847
$216,369
$223,432
$230,061
$223,832
$217,867
$212,156
$206,684
$207,453
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25

1B Results



Total Revenue
Total After-Tax Returns
Annual costs ($)
NPV
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$0
-$20,000
-$40,000
-$60,000
Dollar amount ($)
Year
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
-$242
$9,004
$17,634
$25,686
$33,195
$40,192
$46,708
$52,772
$58,411
$63,651
$68,516
$73,028
$77,209
$81,079
$84,657
$87,960
$91,883
$95,509
$98,858
$101,945
$104,788
$94,953
$85,555
$76,573
$67,987
$67,281

NPV: All Scenarios



Base Model Findings

- Project revenue was driven significantly by ITC and REC payments to the project:
  - The upfront payment of the ITC (modeled in Year 0) reduced the ongoing debt payments.
  - The larger the ITC value, the larger the annual cash flow, thus increasing the NPV at a faster rate.
  - REC payments were key to augmenting the subscription payments, which by themselves did not produce a net positive annual cash flow.
  - The annual net revenue was positive while REC payments continued; after REC payments ended, in Year 21 and forward, the subscription revenue was not large enough to offset costs, which generated a negative cash flow, reducing the final project NPV.
- The project was sensitive to administrative and operational costs, especially program costs, which correlated with project size (e.g., $/kW) thus scaling with the project:
  - Ongoing costs appeared the most impactful on project economics, because the costs were additive and increased with inflation over the life of the project, which already had a small and decreasing net positive cash flow as energy production and the related economics decreased with time.
  - Alternatively, one-time upfront fees, such as subscriber acquisition costs, were less impactful because they were more easily offset by the ITC payment in Year 0 and had a smaller indirect impact on net revenue in outlying years through increasing the debt payments.

Base Model Findings (cont.)

- Generally, the project economics correlated directly with economies of scale (in which larger projects have better economics, all other factors held constant), with one exception:
  - The CAPEX costs for Scenarios 2A and 2B were slightly higher than the “1” scenarios, because the project was only marginally larger (200 kW vs 500 kW) while including more expensive ground-mount costs.
  - Scenario 2A matched the economies-of-scale trend with a greater NPV than 1A, while Scenario 2B did not match the trend and the NPV decreased from Scenario 1B to 2B.
  - The inconsistency correlated with the difference in ITC payment:
    - Doubling the ITC payment from 30% to 60% (Scenarios B vs. A) did not produce a linear increase in NPV.
    - An increase in ITC by 2x provided an NPV increase greater than 2x.
  - Therefore, A scenarios had more than a 2x greater NPV than B scenarios, all else held equal.
- Therefore, while the NPV for Scenario 2B was lower than 1B, the non-linear increase in NPV between B and A scenarios driven by the ITC increase meant the 2A NPV was still greater than the 1A NPV.
  - This brought the ”A” scenarios back in line with the economies-of-scale theory, while “B” scenarios were not and were driven by CAPEX cost trend.

Lease Cost Sensitivity

- While a lease cost component was assumed and included for Scenarios 1 and 2, no additional or specific costs were included for any of the scenarios modeled.
- Identifying a representative lease cost is hard, given the variability by location in the value of roof space or land use.
- With that in mind, for all scenarios, sensitivities were run to identify the maximum annual payment (increasing with annual inflation) that the project could bear until the NPV for the developer approached but did not surpass $0.
- Generally, larger projects can bear a bigger payment, which follows logically with the economies of scale seen already and the fact that a larger project requires more land.
- The exception to this trend was seen between 1B and 2B; as previously discussed, the slight increase in CAPEX was not offset by a 30% ITC, decreasing project economics.

Scenario	Annual Lease Cost When NPV=$0
1A	$11,235
2A	$22,407
3A	$202,262
1B	$3,643
2B	$2,207
3B	$70,907

Program Administrative Costs Sensitivity

- Discussed earlier, annual costs had a larger impact on the project's overall economics than upfront costs.
- Two costs that are hardest to determine at project/program outset are subscriber acquisition and management costs.
- The sensitivity of project economics was modeled to identify the largest upfront and annual costs on a $/kW basis that the project could bear before the NPV fell below $0.
- These are costs the developer would incur but not the subscriber, because no upfront fees are allowed under SFA, and the subscription and credit rates are fixed.

Scenario	Upfront Cost ($/kWdc) When NPV=$0	Annual Cost ($/kWdc) When NPV=$0
1A	$967	$74
2A	$807	$65
3A	$703	$59
1B	$432	$44
2B	$237	$33
3B	$360	$40

For reference: Base model costs were $175/kW and $30/kW, respectively, for upfront and annual costs.

Subscriber Perspective

- A 4-kW subscription would provide a Year 1 utility bill cost savings of ~$222 to the subscriber.
  - This correlates to ~$18.50/month.
- The combined NPV for all customers subscribed is shown at the right for each scenario.
  - The NPV is the same for A and B scenarios, as the subscriber pays the same amount and receives the same credit.
- The net benefit to an individual subscriber is dependent on the size of their subscription.
- The NPV of a block 1-kW subscription is ~$960/kWdc for all scenarios.
  - **A standard 4-kW subscription would create an NPV for a single subscriber of ~$4,800.**

Scenario	Subscribers' NPVs
1	$240,037
2	$594,732
3	$6,395,490

Subscriber Perspective (cont.)

- The subscriber savings calculated are based on the minimum required savings from Ill SFA.
- The project owner may choose to provide additional savings to subscribers as project economics are refined:
  - Increased savings is likely to entice subscribers and increase the ease of acquisition.
  - If the project is being owned and operated by a nonprofit, they may choose to pass any or all net income to subscribers via increased savings.
    - This is specifically applicable because the project economics modeled all have positive a positive developer NPV, meaning additional subscriber savings are possible.
- Furthermore, the model performed calculations assuming that the subscription costs and credit rate ($ amount) both increased annually at the inflation rate entered:
  - This means that the subscriber will receive a small marginal increase in savings over time, as the credit rate grows slightly quicker than the costs.
  - However, based on Ill SFA rules, if the credit rate set by the utility were to increase at a rate larger than inflation, which is entirely possible, the net savings for the subscriber would grow more quickly.
- An alternative model would be for the subscription cost to remain constant for the life of the project, and the credit would grow as electricity rates increase:
  - This model uses a hedge methodology for subscribers to receive increased savings in later years of their subscription.

Anchor Tenant Considerations

The addition of an anchor tenant to a project introduces numerous additional considerations that will impact project economics.

- A large anchor tenant reduces the number of subscribers that a project must fill to ensure it is fully subscribed, which can reduce subscription acquisition and management costs.
  - This is especially applicable to subscriber turnover or churn. If a project has high churn rates, an anchor tenant can reduce management costs with a secure long-term subscription.
- An anchor tenant that is secured at an early stage of a project can also reduce financing risk and may even enable lower interest rates.
- An anchor tenant would also likely be compensated for net metering at a different rate than residential subscribers, which could reduce project revenue via a lower subscription rate.
  - Ill SFA requires certain anchor tenants to receive a higher savings rate at 65% if the ITC is obtained by the project owner.

Anchor Tenants (cont.)

- Ill SFA program has limitations around anchor tenants, including:
  - Inclusion of an anchor tenant in the project must be noted at time of application to SFA program.
  - REC payments for the anchor tenant portion of the project will be made at Illinois Shines rates and not SFA rates (Ill Shines REC contract is for 15, not 20 years).
  - The anchor tenant may not subscribe to more than a 40% share of the system’s capacity.
- An anchor tenant will therefore provide a potential reduction in administrative costs while reducing REC payments to the project overall.
- These trade-offs mean inclusion of an anchor tenant should be considered early on, and the potential administrative savings should be weighed against the reduction in REC payments.

Egyptian Electric COOP Alternative

- The modeling and assumptions completed were all based on a project and subscribers located in Ameren Illinois' territory.
  - This selection was made as Ameren has readily available data and a program deployed for community solar.
- Developing a project in Egyptian Electric COOP territory would enable more subscribers in Jackson County to have access to community solar but would require additional input and performance by the COOP.

Egyptian Electric COOP (cont.)

- The COOP currently has rate schedules, which do not address virtual net metering.
  - The COOP has interconnection and net metering policies in place for full retail net metering of <40-kW systems behind the meter.
  - The current net metering policy is currently closed to new members; the program reached its capacity in spring 2021.
- The COOP would need to develop virtual net metering rules and a tariff that dictates the rate at which subscribers would be compensated for their subscribed energy, in alignment with the Illinois ICC and Ill SFA program rules, should that be the aim of the program.
  - This rate could simply expand the current net metering tariff to include virtual net metering and raise the subscriber cap for the program.
- The net metering rate that a subscriber in the COOP's territory would receive would dictate the overall project economics.
  - If the rate were below the Ameren price to compare value ($0.07877/kWh), the project's economics would degrade compared with those modeled.
- Given that the details of a virtual net metering rate and its compensation value are unknown, the impacts were not specifically modeled.

CAPEX Sensitivity

- Capital costs vary for numerous reasons, including market changes, local supply and labor costs, and contractual requirements.
- The baseline CAPEX costs were based on NREL's Annual Technology Baseline, but any value above these assumptions resulted in worse project economics.
- Therefore, a sensitivity was run to determine the greatest CAPEX cost that the project could bear for each scenario before reaching a ~$0 NPV.
- The delta between baseline models and the max CAPEX was also documented.

Scenario	CAPEX Cost ($/Wdc) When NPV=$0	Δ in CAPEX ($/Wdc)
1A	$3.66	$1.87
2A	$3.39	$1.49
3A	$2.39	$1.25
1B	$2.14	$0.35
2B	$1.98	$0.08
3B	$1.39	$0.25

Findings

- Under the modeled baseline assumptions, projects were economically advantageous for all scenarios for the developing party and subscribers.
- Subscriber savings remained consistent across scenarios due to SFA 50% savings requirement:
  - This holds true unless subscriber classes change to include an anchor tenant.
- Project economics were driven in large part by the ITC and REC payments, and the economics were notably sensitive to ongoing annual costs:
  - Costs incurred as one-time fees in Year 1 are easier to absorb over the life of a project as they are more certain and do not reduce revenue in later years.
  - On the contrary, ongoing costs, like O&M, leases, and program admin have a greater impact with relatively small changes, because the costs grow over time with inflation and reduce the net revenue that a project needs to make up for the CAPEX outlay.
- ITC and project NPV had a non-linear relationship; an increase in ITC increased the NPV by more than 1-1.
- All results explored were based on numerous assumptions that changed as project development matured:
  - These included factors like interest rate, system design and performance, actual ITC value obtained, payout timing of ITC, tax liability and project ownership model, etc.

Key Findings

- Community solar development is economically viable in Jackson County within Ameren's service territory through structures that can reduce subscribers' energy costs and increase access to renewable energy under the current Ill SFA program.
- All potential project designs and scenarios modeled provided the project developer and subscribers with a net positive economic outcome, meaning that the market is well suited to supporting a community solar project.
- The Ill SFA program and enabling state legislation creates an environment that supports favorable economics for community solar development (particularly projects that include LMI subscribers) and reduces developer and subscriber risks via well-regulated consumer protection rules, project verification protocols, and a history of successful community solar projects.
- The notable hurdles left to address are refining project economics now that viability has been proven, expanding access to community solar projects for more electricity consumers by implementing a community solar program in the COOP territory of Jackson County, and gathering community support by engaging and educating potential subscribers and reducing the friction of subscriber acquisition by building trust in the community.

Next Steps

- Jackson County can take the findings from this modeling and move forward with some thoughtful next steps:
  - Refine the community's goals of community solar, including which (if not both) utility territories they would like a project developed in.
  - Engage community organizations and trusted partners to increase knowledge and interest in community solar using readily available market and education materials (see the National Community Solar Partnership resources for examples).
  - Engage in discussion with potential project developer/owners (e.g., using a request for information) and work toward an investment-grade analysis.
  - Further engage key project stakeholders, including potential site owners, utility staff, Ill SFA program staff, financiers, and more. Work with stakeholders to assign responsibility and next steps to ensure accountability.

Appendix and Disclaimer

System Design: Ground Coverage Ratio

- GCR was used for land area calculation for lease costs in SAM:
  - The lease cost was included in the O&M costs for rooftop solar, so the GCR was irrelevant for SAM modeling and lease calculations.
- Ground-mounted system GCR was set by running parametric analysis of GCR and system tilt to identify the optimal combination:
  - GCR can vary a great deal between sites, latitudes, acceptable losses, and module type (https://www.energy.gov/sites/default/files/2022-01/lbnl_ieee-land-requirements-for-utility-scale-pv.pdf).
  - Fixed tilt values typically range more from 0.4-0.5 GCR (https://www.energy.gov/sites/default/files/2022-01/lbnl_ieee-land-requirements-for-utility-scale-pv.pdf) for ground-mount system.
- For rooftop system (200 kWac), the GCR was left at default of 0.3; for the ground-mount systems (500 kWac and 5 MWac), the GCR was set at 0.4.
  - The 0.4 GCR used the lower value of typical designs, assuming no land limitations, as it provides higher system energy output.

Illinois Shines REC payments

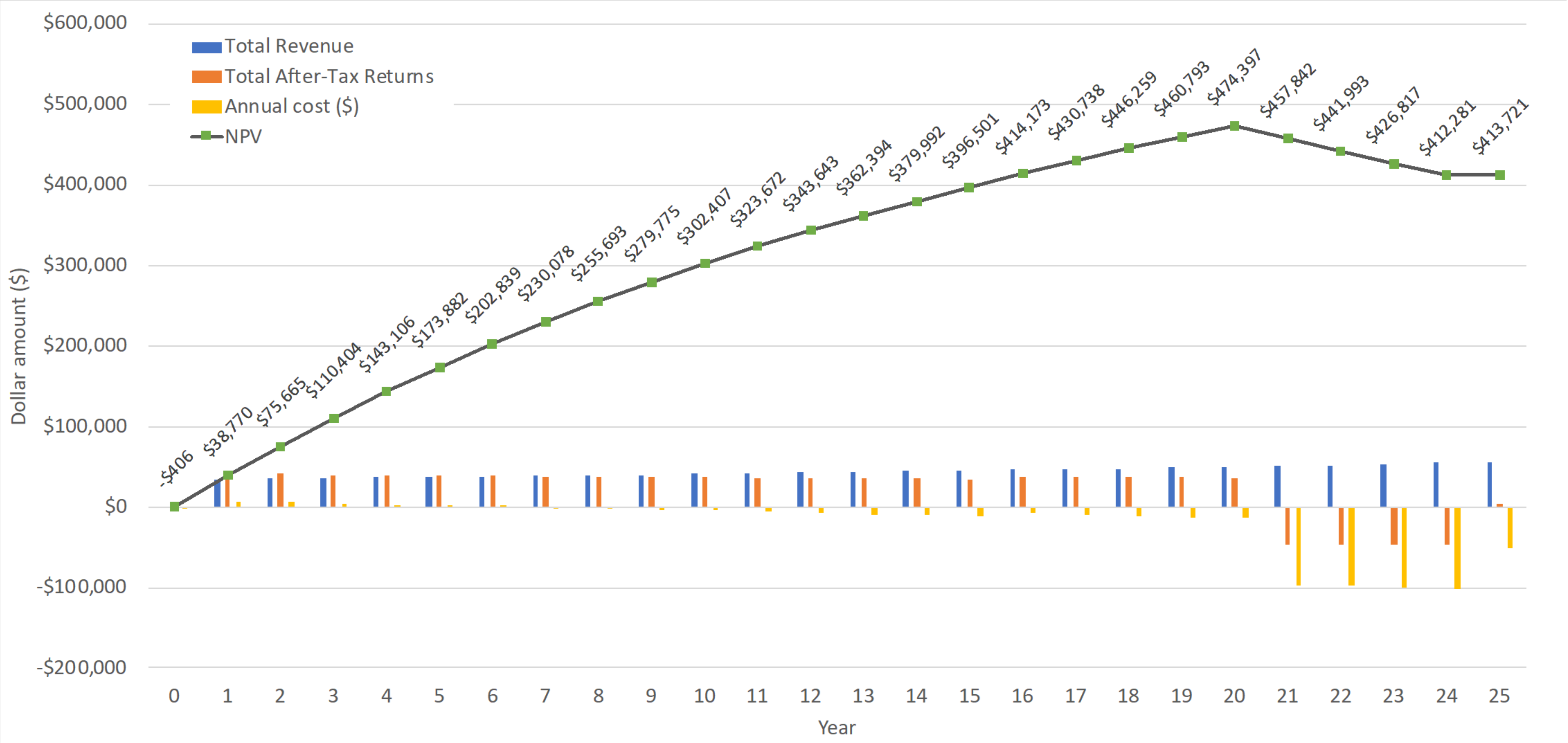
Traditional Community Solar

	Group A	Group B
0 - 25 kW	$55.08	$63.48
25 - 100 kW	$58.94	$71.92
100 - 200 kW	$60.79	$73.22
200 - 500 kW	$56.96	$65.20
500 - 2000 kW	$49.94	$56.08
2000- 5000 kW	$39.27	$42.39

Group A is for projects located in the service territories of Ameren Illinois, MidAmerican, Mt. Carmel Public Utility, and rural electric cooperatives and municipal utilities in the Midcontinent Independent System Operator, and Group B is for projects in the service territories of ComEd and rural electric cooperatives and municipal utilities located in PJM.

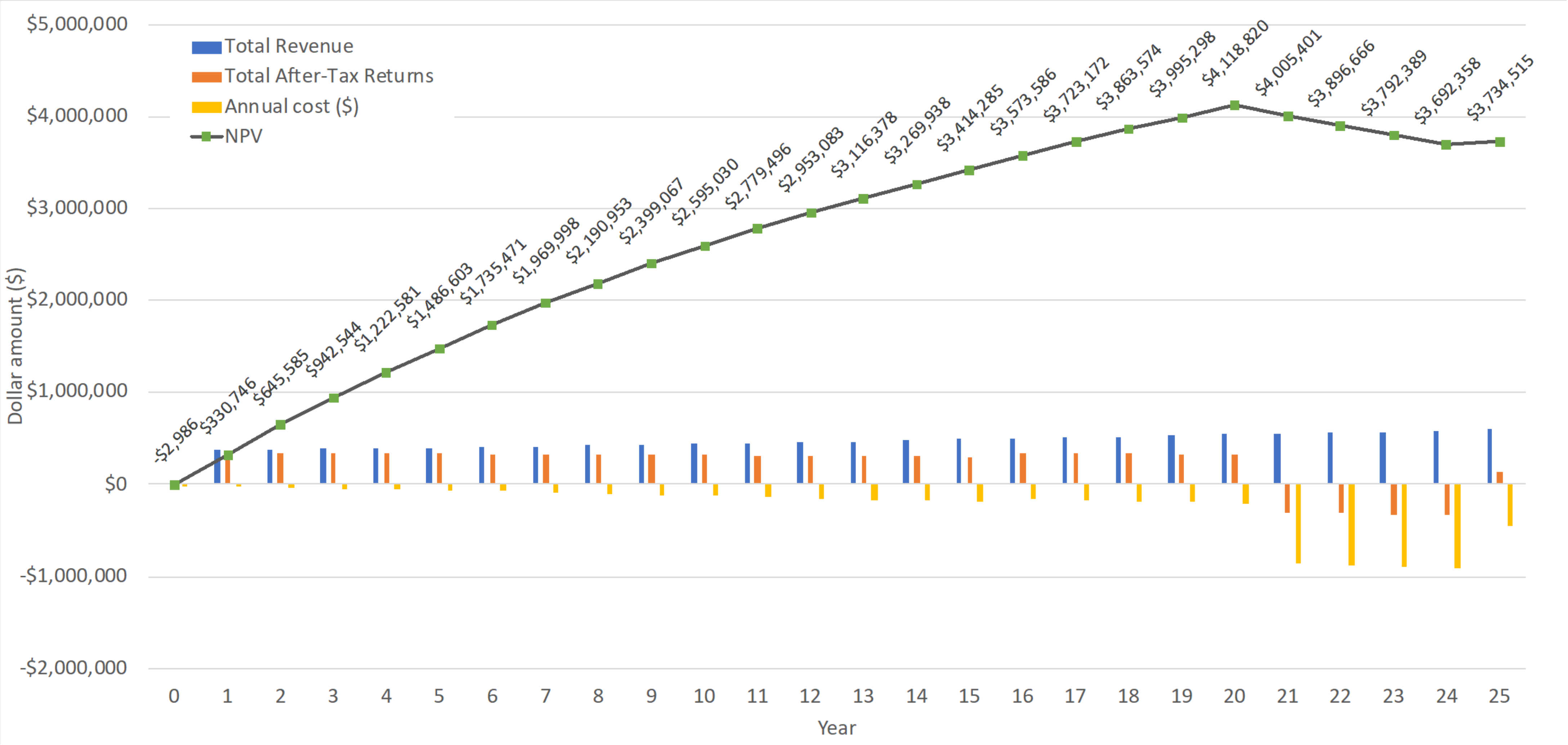
Additional Results

2A Results



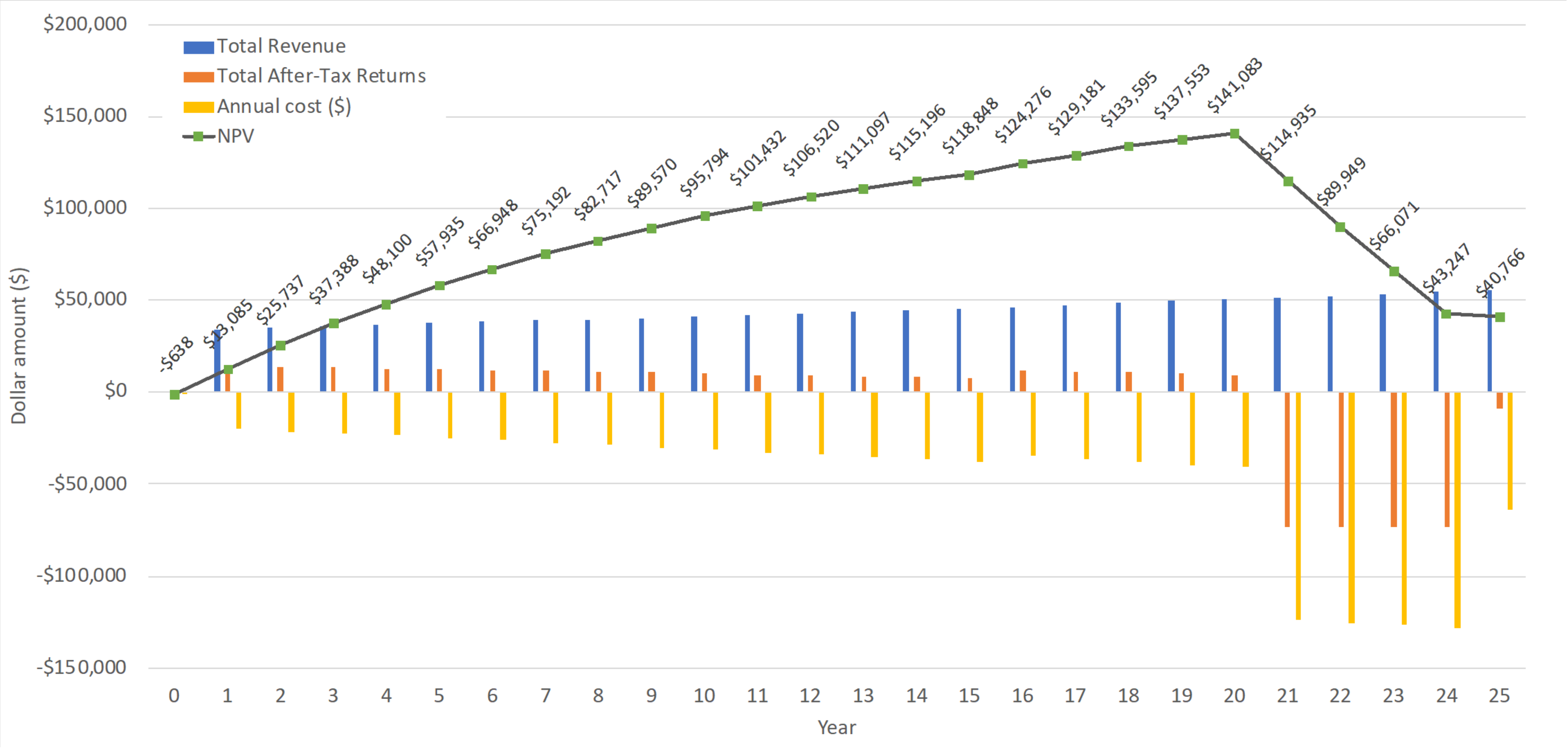
Total Revenue
Total After-Tax Returns
Annual cost ($)
NPV
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
-$100,000
-$200,000
Dollar amount ($)
Year
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
-$406
$38,770
$75,665
$110,404
$143,106
$173,882
$202,839
$230,078
$255,693
$279,775
$302,407
$323,672
$343,643
$362,394
$379,992
$396,501
$414,173
$430,738
$446,259
$460,793
$474,397
$457,842
$441,993
$426,817
$412,281
$413,721

3A Results



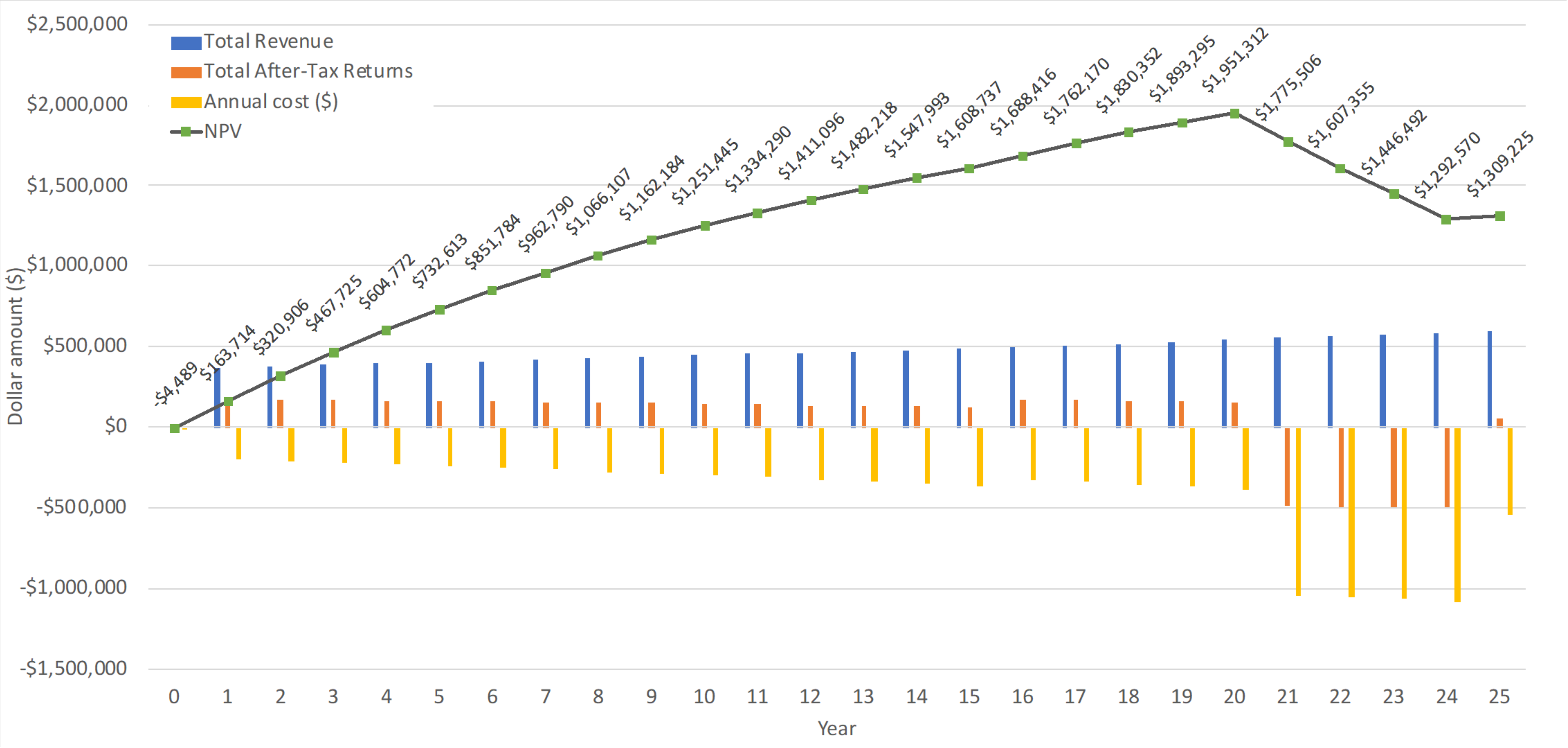
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$0
-$1,000,000
-$2,000,000
Dollar amount ($)
Total Revenue
Total After-Tax Returns
Annual cost ($)
NPV
-$2,986
$330,746
$645,585
$942,544
$1,222,581
$1,486,603
$1,735,471
$1,969,998
$2,190,953
$2,399,067
$2,595,030
$2,779,496
$2,953,083
$3,116,378
$3,269,938
$3,414,285
$3,573,586
$3,723,172
$3,863,574
$3,995,298
$4,118,820
$4,005,401
$3,896,666
$3,792,389
$3,692,358
$3,734,515
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Year

2B Results



Total Revenue
Total After-Tax Returns
Annual cost ($)
NPV
$200,000
$150,000
$100,000
$50,000
$0
-$50,000
-$100,000
-$150,000
Dollar amount ($)
-$638
$13,085
$25,737
$37,388
$48,100
$57,935
$66,948
$75,192
$82,717
$89,570
$95,794
$101,432
$106,520
$111,097
$115,196
$118,848
$124,276
$129,181
$133,595
$137,553
$141,083
$114,935
$89,949
$66,071
$43,247
$40,766
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Year

3B Results


Total Revenue
Total After-Tax Returns
Annual cost ($)
NPV
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
-$500,000
-$1,000,000
-$1,500,000
Dollar amount ($)
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Year
-$4,489
$163,714
$320,906
$467,725
$604,772
$732,613
$851,784
$962,790
$1,066,107
$1,162,184
$1,251,445
$1,334,290
$1,411,096
$1,482,218
$1,547,993
$1,608,737
$1,688,416
$1,762,170
$1,830,352
$1,893,295
$1,951,312
$1,775,506
$1,607,355
$1,446,492
$1,292,570
$1,309,225

Context Slides

Illinois Legislation and Policies

State	Initial Year	Policy or Program Name	Initial Policy/Regulation	Notes
Illinois	2016; 2019	SFA Program (2016) Active since 2018 Illinois Shines (2019) [Adjustable Block Program] Active since 2019	Senate Bill No. 2814 Public Act 099-0906 An Act Concerning Regulation (2016) Public Act 102-0662	Ill SFA enables multiple community-solar-related subprograms, including the Adjustable Block Program (also called the Illinois Shines Program), the Low-Income Community Solar Program, and the Low-Income Community Solar Pilot Program. Illinois Adjustable Block Program was developed by Illinois Power Agency in 2019 through the Climate and Equitable Jobs Act. This program is also known as Illinois Shines.

Other Policies/Regulations in Illinois:
Docket 17-0838: Final Long-Term Renewable Resources Procurement Plan (2018)
SB2408 Public Act 102-0662 Climate and Equitable Jobs Act (2021).

Community Solar Resources

- The Community Solar Playbook (National Rural Electric Cooperative Association)
- The Municipal Utility Community Solar Workbook (American Public Power Association)
- Community Solar Policy Decision Matrix (Coalition for Community Solar Access)
- A Guide to Community Shared Solar: Utility, Private, and Nonprofit Project Development (U.S. Department of Energy)
- Low-Income Community Solar: Utility Return Considerations for Electric Cooperatives (NREL)
- Many more, including financial and technical modeling tools, on the National Community Solar Partnership website.

National Policy Perspective

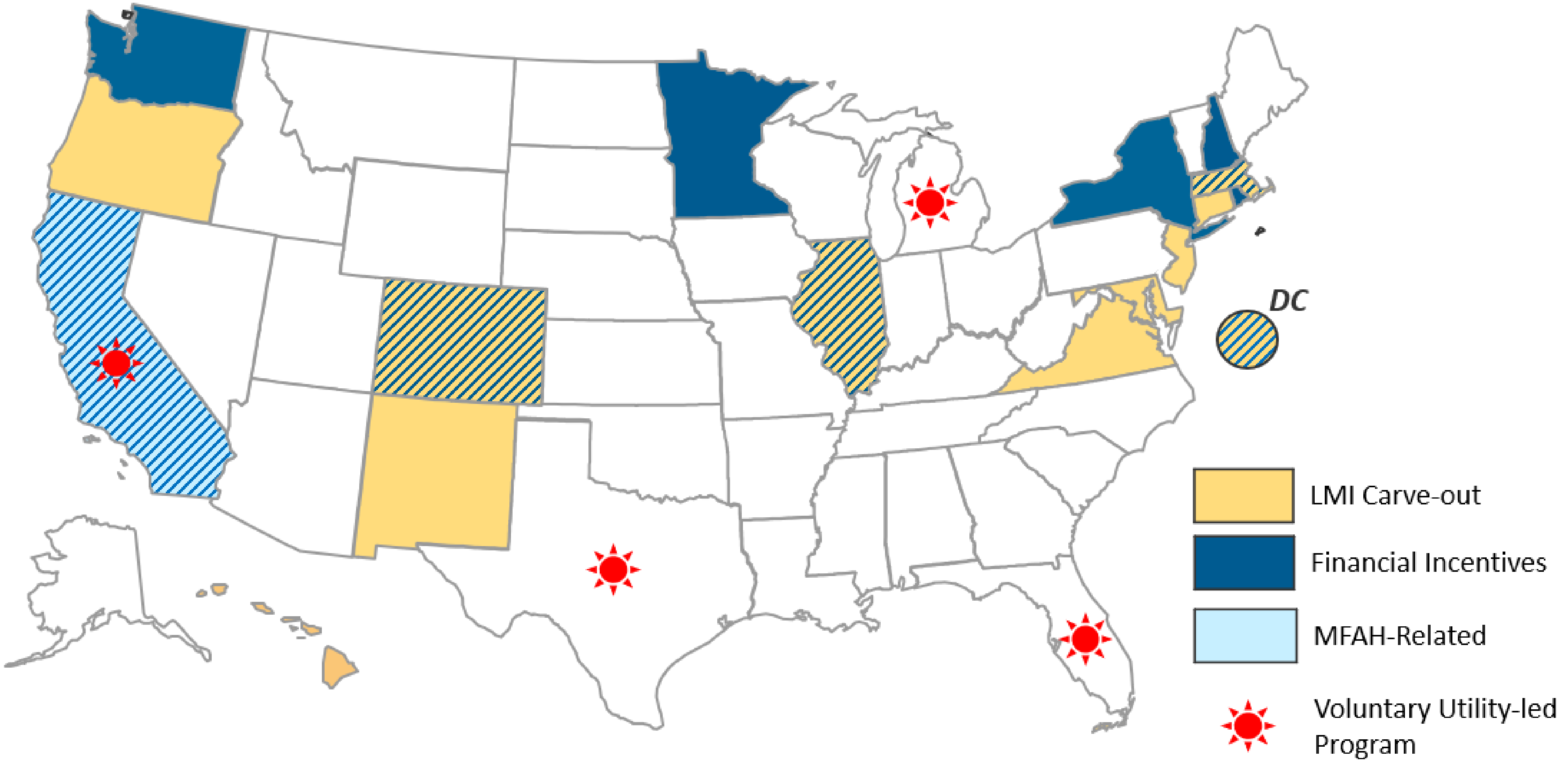


Image source: https://www.nrel.gov/docs/fy20osti/75982.pdf

MFAH: Multifamily affordable housing

Notice

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Thank you

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