Technical Appendix

For state-level reports on the effect of solar smart permitting by Greenhouse and the Climate Solutions Lab

The model is based on a set of benchmarks, which provide a detailed representation of the average hard and soft costs involved in solar photovoltaic projects. We use these to create a baseline or reference scenario which projects the "business-as-usual" price of solar in the absence of smart permitting.

We only model costs for a generic solar installer, and do not generate different estimates for different sizes of firms. Some small firms may face lower acquisition costs because they build long-term relationships with a few neighborhoods, but also face higher equipment costs because they lack negotiating power. A large firm might have greater economies of scale but also deal with more cancellations. Lean firms may have lower overhead. Firms may find themselves making lower profits. Because of the diversity of the solar installation market, our model cannot perfectly capture the prices faced by every firm at the same time.

We project outcomes through 2040. Projections are intended to capture both the immediate "first-order" effects of smart permitting, as well as longer-term "second-order" effects that only materialize as market participants change their business models in response. All of the projections are subject to uncertainty, especially as we get further from the present.

Baseline Hard Costs

Hard costs include the price of modules, inverters, and electrical and structural balance of system expenses. To estimate hard costs, we use the National Renewable Energy Laboratory (NREL) benchmarks for residential solar photovoltaic systems (Ramasamy et al. 2022).[1] These are derived from bottom-up modeling, using input price data and interviews with firms to derive average national costs. We use their "Modeled Market Price" (MMP) as our starting point, which is designed for "[n]ear-term policy and market analysis based on disaggregated system costs."

[1] We use Ramasamy et al. (2022) rather than Ramasamy et al. (2023) because methodological changes between these versions mean that some cost components are no longer broken down conveniently in the way needed to make our state-level adjustments.

The Ramasamy et al. (2022) prices are reported in 2021 dollars, which we convert to 2023 dollars using the Federal Reserve Bank of Minneapolis' Inflation Calculator.[2] We assume that hard costs are primarily determined at the national level and do not make state-level adjustments for them.

To project how hard costs will change over time we use NREL's Annual Technology Baseline (NREL 2024b), which models energy technology cost changes in different scenarios. We use their "Conservative" scenario for residential solar photovoltaics, which assumes:

- an expanding market for solar photovoltaic systems,
- hard cost reductions on the low end of manufacturers' expectations,
- no changes in soft costs,
- additional trade barriers which limit the cost reducing effect of competition from foreign manufacturers.

We base our estimate of hard cost changes on the ATB's projections for Capital Expenditure per kW of capacity. Because the scenario we use does not assume any soft cost changes, we assume that all of the projected changes in capital expenditure are due to changes in hard costs and any effect hard cost changes have on installer profit margins.

We model the costs for a representative photovoltaic system size, designed to roughly match the median system size in the state (6.4 kW).[3] Our representative system has 18 modules, each with an efficiency of 0.203, an area of 1.77 m^2, and an average radiation under standard test conditions of 1000 W, for a total capacity of 6.47 kW. Except for size this matches the parameters in Ramasamy et al. (2022).

Modeling was primarily carried out in Excel, with data preparation and cleaning performed in Python. Modeling of hourly energy use and utility charges was performed in the NREL System Advisor Model (NREL 2024c).

Baseline Soft Costs

Soft costs include customer acquisition, permitting, inspection, interconnection, installation labor, overhead, sales tax, and installer profits. We use two different soft cost benchmarks and derive two parallel sets of estimates from them.

The first set of soft cost benchmarks are largely derived from Ramasamy et al. (2022), with modifications for the state context. As with hard costs, we use their "Modeled

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[2] The inflation calculator is based on the urban consumer price index (Minneapolis Fed 2024). All other prices in our model are reprojected to 2023 dollars.

[3] Median system size is from Barbose et al. (2024). Unless otherwise specified all watt and kilowatt values are expressed as direct current.

Market Price" estimates for soft costs. But as the authors carefully note, the MMP is not the same as the market prices actually observed in the real world, and can be substantially lower than observed prices.[4] We expect the discrepancy to affect soft costs much more than hard costs, since soft costs are determined more by local factors like labor costs and permitting regimes.

A top-down approach using locally reported market prices would capture the prices consumers actually face. But it would lack the disaggregated component cost estimates we need in order to model how smart permitting will change different cost components. We resolve this by taking the MMP and adjusting specific components to match more closely current input prices in the state.

Soft Costs Based on NREL Data

We make the following changes to the Ramasamy et al. (2022) MMP:

- **Customer acquisition:** We replace the MMP estimate with the most recent estimate from energy analytics firm Wood Mackenzie, which projects that CAC will be $0.87/W in 2024, and decline by 1% annually through at least 2028 (McGarvey 2023). For our model, we assume that baseline CAC costs will continue to decline by 1% annually after 2028.[5]
- **Permitting, interconnection, and inspection (PII):** These are bundled in MMP into one fixed cost per project, but given our focus on permitting it is important to disaggregate these costs.
    - We build a bottom-up model of these costs, starting with the average hours required for permit preparation, permit submission, inspection, interconnection, and incentive applications from Seel et al. (2014). We combine these with estimates of the share of different occupations in completing each of these tasks from Ardani et al. (2012). We obtain 2023 occupational wage data for the state from BLS (2024a).[6] We scale up wages to fully-loaded employer costs in the same way as with installations above (BLS 2024b).
    - To take into account the labor involved with permit applications that take longer than expected, we assume that 35% of permits need to be

[4] "[N]o individual estimate under any approach can reflect the diversity of the PV and storage manufacturing and installation industries. The MMP benchmarks are designed to reflect typical costs, but these costs do not reflect the experiences of all installers and customers. For instance, MMP benchmarks are based on national average costs and do not necessarily reflect the distinct experiences of developers in local markets." Ramasamy et al. (2023), p. 17.
[5] These costs are high relative to the Ramasamy et al. (2022) benchmark, but they are in line with other reports, like Ardani et al. (2012), which report CAC of $0.67/W in 2012, which would be $0.89/W in 2023, and with our own discussions with installers.
[6] We match the "permit procurement" class in Ardani et al. (2012) to "project management specialists" in BLS (2024a), "administrative staff" to "office clerks, general," 'installer" to "solar photovoltaic installer," and "electrician" to "electricians."

submitted twice.[7] We model this by adding 35% of the cost of permit preparation and submission to the overall cost for the average permit.
    - We use data on permit fees from SolarTRACE (NREL 2024a) and take the average, weighted by installations in each jurisdiction.
- **Installation:** MMP installation costs are a blend of construction labor (0.56/hours per m^2 of panels) and electrician labor (0.51/hours per m^2 of panels). We use state-specific wage rates for solar photovoltaic installers and electricians from BLS (2024a), scaled up by using the average ratio of fully-loaded employer costs to employee wages in the "natural resources, construction, and maintenance occupations" (BLS 2024b).
- **Overhead:** Overhead costs in the MMP are presented as a fixed amount ($2,389 per project). But many overhead costs are sensitive to local costs like labor, taxes, energy prices, rents, etc. So we scale MMP overhead to state price levels using the regional price parities from the Bureau of Economic Analysis (2024), which "measure the differences in price levels across states and metropolitan areas for a given year and are expressed as a percentage of the overall national price level."
- **Sales tax:** the MMP includes a sales tax rate of 5.1%, but we set it to the state rate, unless the state exempts solar installations from sales tax.[8]
- **Profit:** the MMP rate of profit is fixed at 17% of "all direct costs, including hardware, installation labor, sales tax, installation, and permitting fees," excluding customer acquisition costs and overhead. We leave this unmodified initially, though the absolute size changes in our model as the other direct costs change.

Our estimates are somewhat lower than the reported market prices in Barbose et al. 2024, but our estimates do not include financing costs, which may change the full costs faced by consumers.

Soft Costs Based on OpenSolar Data

To complement our MMP estimates, we also use a second source of soft cost benchmarks from OpenSolar, a solar design and sales application with aggregate data on many solar installers' cost structures.[9] These data were structured slightly differently than the Ramasamy et al. (2022) benchmarks.

- **Customer acquisition:** unlike the MMP data, the OpenSolar data breaks out customer acquisition into upfront sales and marketing and post-sales costs

[7] The 35% figure is from our consultation with OpenSolar (see discussion below on this source).
[8] DSIRE (2024).
[9] These cost estimates were shared directly in aggregate form by OpenSolar staff, without revealing any individual customer data.

(i.e. commissions). The OpenSolar customer acquisition cost estimate is $0.54/W. This is lower than the Wood Mackenzie cost, which we attribute to the exclusion of customer care costs.

- **Customer care:** this line item includes the costs of arranging site visits, managing schedule changes, and setting up installations, as well as changing orders and arranging new visits and contracts when revisions are made. The OpenSolar estimate includes specific line items for initial work with customers as well as follow-up work after revisions. We adjust the fully-loaded hourly labor costs using regional price parities (BEA 2024), and follow OpenSolar in assuming a 35% revision rate.
- **Design and engineering:** this line item covers planset creation and redesigning plansets after design changes. As with customer care we adjust the costs using regional price parities (BEA 2024) and assume a 35% revision rate.
- **Site visits:** this line item covers the actual truck rolls to the site for design and, when necessary, revisits to accommodate redesigns after permit rejections. We make the same adjustments as for design and engineering above.
- **Overhead:** OpenSolar provides three estimates of overhead, including project management costs, software and operating expenses for customer care and design and engineering, and other general overhead. The OpenSolar figures do not include a specific profit estimate, so this would be part of the general overhead figure. The management cost assumes a management payroll of $140,000/year divided by 1200 projects/year. The software and operating expenses assume a fixed cost of $155,000/year divided by 1200 projects/year. Converting them to a per system cost and then a per watt cost using our representative system, and adding the general overhead cost per watt, we arrive at a baseline estimate, to which we then apply the regional price parity adjustment.
- **Permitting, inspection, and interconnection:** this includes permit fees and truck rolls to the jurisdiction and to the site for permits, inspections, and interconnections.
    - We replace the national estimate of the average permit fee with the state-specific average permit fee. We calculate the state-specific fee by taking an average of medians fee by jurisdiction in SolarTRACE (NREL 2024a), weighted by each jurisdiction's share of solar installations in the state from 2017 through 2023.
    - OpenSolar assumes that roughly 50% of permits need to be submitted in person, but this is a national estimate. To calculate the share of state jurisdictions with online submission, we used NREL's SolarTRACE (NREL 2024a) dataset and divided the number of jurisdictions with confirmed online permitting by the total number of jurisdictions in the state.
- **Installation:** OpenSolar records this as a flat labor cost per watt, which we convert using price parities.

In our baseline scenario we do not assume any changes in soft costs over time, given that soft costs have remained roughly stable in recent years.

By using two mostly independent cost models built through different methods (bottom-up estimates from industry surveys versus data from a software platform serving the solar industry), we increase our confidence that we are capturing realistic costs for solar installers.

Cancellations

Neither the NREL or OpenSolar figures include a specific line item for expenses related to projects that are cancelled before installation. But surveyed installers report that permitting is a major driver of cancellations (Cook et al. 2021), and we expect those cancellations to generate costs that must be spread across remaining projects. We do not add these cancellation costs directly to the models just described. Instead, we assume that the overhead costs in those sources already incorporates cancellation-related expenses.

We estimate the size of those expenses using the following procedure, combining state-level cancellation rates from Ohm Analytics (2024) with installer assessments of the share of cancellations that are driven by permitting (Cook et al. 2021).

- According to Cruce et al. (2022), 22% of projects that reach the permitting stage nationally are unsuccessful. Only 2% of projects end during the permitting stage itself. But installers also rate permitting delay as the most important factor in customer cancellations (Cook et al. 2021), a sentiment consistent with our own installer interviews. We interpret this to mean that permitting delays do cause consumers to cancel, but that there is little pressure for them to make the final decision until the permit is approved, when allowing the project to continue would actually incur additional costs for them.
- Ohm Analytics provided data on the permitting process for 68,449 solar photovoltaic projects that submitted applications across 83 jurisdictions in our states of interest between the second quarter of 2022 and the first quarter of 2024. We used these to estimate state-level cancellation rates, subtracting the number of finaled permits from the number of initial applications, and dividing it by the number of initial applications.
- To estimate how many of these cancellations are due to the permitting process itself, we use results from a survey by Cook et al. (2021), where installers report the most important reasons for cancellations. We estimate the permitting-driven cancellation rate as the state-level post-application cancellation rate multiplied by the share of respondents that view permitting as the most important driver of cancellations (37%) plus half the share that

view permitting as the second most important driver of cancellations (21%, divided by 2). We multiply this by the post-application cancellation rate to estimate the rate of permitting-driven cancellation.
- Using that rate, we can infer the number of projects that would have been completed in the absence of permitting-induced cancellations in each state (multiplying the number of completed projects by 1 / (1 - % of Cancellations driven by permitting in the state).
- We estimate the cost of a single cancelled project by assuming that a share of each project's costs cannot be recovered when a project is cancelled after the permitting application has already been submitted.
  - For the model based on Ramasamy et al. (2022), we assume that the permit fee and labor costs for permit preparation, submission, and revision cannot be recovered. This represents 77% of the total permitting, inspection, and interconnection costs. We assume that at least 50% of overhead costs per project have been incurred by the time of cancellation and cannot be recovered. Data from OpenSolar suggests that 70% of customer acquisition costs are incurred before the sale (with 30% only being paid after successful installation), and so we assume that each cancelled project also incurs 70% of a successful project's customer acquisition costs. To partially offset these costs, we assume installers can keep a $500 security deposit.
  - For the model based on OpenSolar data, we use a similar procedure but with a slightly different list of included items reflecting this dataset's different organization of costs. We assume permit fees, design and engineering expenses, site visits, and labor and travel costs for permit preparation, submission, and revision cannot be recovered after cancellation. We assume 50% of overhead and customer care expenses are lost, and 70% of customer acquisition costs (see above). We assume the same $500 security deposit.
- We apply the cost per cancelled project to the remaining uncancelled projects, assuming that these costs are incorporated into the general overhead costs of solar installation firms.

Cost Changes Induced by Smart Permitting

In order to model how smart permitting changes sales prices for solar, we first need to model how smart permitting changes costs for solar installers.

Gradual Realization of Potential Cost Reductions

For the following calculations, we start by estimating the potential cost reductions that would be made possible by smart permitting. But we do not assume that all these potential cost reductions will be realized instantly. Even if installers were to instantly pass on any cost reductions to their consumers, it would still take time for those cost reductions to materialize. Firms need time to adjust and reconfigure their business processes. Some effects depend on factors like word-of-mouth recommendations, which also take time to accumulate. There may be an adjustment period for jurisdictions as well. And once cost reductions do arrive it may take time for competition to drive pass-through to consumers.

To reflect the gradual nature of market transformation, we assume that the potential cost reductions are only realized slowly at first, but then gather speed as more firms adjust, innovations begin to diffuse, new firms enter, and competition drives pass-through. We model this process using a logistic function, assuming the the realization rate for price reductions starts near 0 in 2025, rises to 50% in 2030, and nears 100% only in 2035.[10] All cost changes in the following subsections are subject to this gradual phase-in.

Potential Cost Changes

- **Hard costs:** we do not model any changes to hard costs due to smart permitting beyond the decreases in the baseline scenario.
- **Customer acquisition:** In the baseline scenario, customer acquisition costs go down by 1% a year. But we expect smart permitting to increase reductions. We model these changes to customer acquisition costs in two ways.
    - First, we expect permitting to create a marginal upfront reduction in customer acquisition costs. Installers can offer more certain installation timelines if they know they can obtain instant permit approval for most projects. Salespeople can get paid more quickly because the delay between contract signing and installation is shorter. And shorter projects with better customer experiences should improve recommendation rates, helping make future customer acquisition easier. We model these combined impacts as an initial 5% reduction in customer acquisition costs, which we consider a conservative estimate based on our interviews with installers.
    - Second, as smart permitting reduces prices, we assume that the resulting increases in demand will also bring down the marginal cost of customer acquisition. This is partly due to spreading some of the fixed costs of customer acquisition over a higher number of completed projects, and the anticipated increase in "peer effect" recommendations as more people experience shorter projects. To model this, we assume that firms' total customer acquisition costs go up sub-linearly with respect to sales volume. Specifically, we assume that if total sales

[10] For the logistic function the carrying capacity L is 1, the logistic growth rate k is 1, the midpoint x_0 is 2030, and x is the current year.

increase by X percent, then total customer acquisition costs only go up by X/2 percent, reducing the customer acquisition cost per project.

- **Permitting, inspection, and interconnection:** To model permitting labor cost reductions, we assume that the labor time involved in each permitting task decreases to match the time for the equivalent task in Germany (Seel et al. 2014). We also assume that permit revisions no longer require additional time, since issues can be resolved during the initial submission. We assume that jurisdictions do not reduce the fees they charge for permits, but also that they use a portion of these fees to cover the cost of the smart permitting platform. We assume no changes in inspection or interconnection costs.
- **Overhead costs:** In our baseline case, we assume that per-project overhead costs remain stable over time as overhead scales with increased volume. In our smart permitting case, as with customer acquisition we assume a 5% initial reduction in cost per project as the complexity of managing individual projects is reduced. Over time, we also expect smart permitting to reduce the amount of back office logistical work needed for each project. We assume that demand increases above the baseline rate can be absorbed with sublinear increases in total overhead. without increasing absolute overhead expenditure. As with customer acquisition, we assume an increase in volume of X percent is associated with an overhead increase of only X/2 percent.
- **Profit:** We assume that smart permitting will reduce barriers to entry and expansion for solar installers (Dong and Wiser 2013), and that this will put downward pressure on installer profits. This includes entry into jurisdictions that installers have previously avoided due to onerous permitting requirements (Ardani et al. 2012). This effect may end up being large, but it will only occur gradually as new firms enter the market and existing firms expand. We conservatively assume that competition enabled by smart permitting will push normal profit margins down by 10% between 2025 and 2040, from 17% in 2025 to 16.2% in 2040. This only applies to the model derived from Ramasamy et al. (2022), since the OpenSolar model does not explicitly estimate installer profit.
- **Cancellations:** we assume that smart permitting eliminates cancellations due to the permitting process. Customers may still cancel for other reasons, but because permitting can be done online and instantaneously we consider that permitting stops being a driver of cancellations.

We incorporate these parameters into four models in Excel: two baseline models and two smart permitting scenarios, based on the Ramasamy et al. and OpenSolar data. We make projections through 2040, assuming that smart permitting is implemented across the state in 2026. We use these models to project the price of new solar photovoltaic systems, the total number of systems installed, and other derived quantities.

Photovoltaic System Performance

In addition to the cost, price, and deployment projections, we also project impacts on the household and social level. We start with NREL's System Advisor Model (NREL 2024c and Blair et al. 2018) to calculate how solar systems will perform. We input the characteristics of our representative system, and run separate models for the state's climate zones. In each climate zone, we use the most populous county as our representative modeling point for obtaining weather data, utility prices, and load shapes.

To represent the specific regional level of solar potential, we obtain hourly solar irradiance at the latitude and longitude of the representative county's population centroid using SAM's built-in interface with the National Solar Radiation Database (Sengupta et al. 2018). To represent regional electricity consumption patterns, we use SAM's built-in interface with the OpenEI Building Load Database, picking the base residential load type (NREL 2021). To represent local utility prices, we select the utility from SAM's built-in interface with the OpenEI Utility Rate Database (NREL 2024d). In some cases this database does not include the rates paid by utilities for residential solar generation, in which case we supplement the data with information from the utility itself.

We use SAM to estimate the hourly electricity generation of the representative system in each climate zone across the whole year. By comparing the hourly load profiles with the hourly generation, SAM generates a projection of how much electricity a household can consume from its own solar panels, and how much it imports from and exports to the grid. Using the rate data it calculates the net impact on annual electricity bills, which we then scale to the total number of systems installed across the state. We preserve the default assumption in SAM that capacity degrades by 0.5% annually.

Savings differ by climate zone (both because the amount of sun and the average load shape differs). We assign each climate zone a share of the annual projected solar deployment proportional to the zone's share of the state's residential photovoltaic potential from NREL's State and Local Planning for Energy project (NREL 2024e).

We also use the "Fixed Operation and Maintenance Expenses" from the Annual Technology Baseline to capture ongoing overhead costs for households, and subtract this from net savings.

We also use SAM to calculate how much energy systems generate, and how much of that energy is used by the household or exported to the grid. We convert hourly energy use estimates into avoided greenhouse gas emissions using state-specific projections of hourly grid intensity from 2025-2050 by the Cambium project (Gagnon et al. 2024). Cambium estimates the long-run marginal emission rate, an "estimate of the rate of emissions that would be either induced or avoided by a change in electric demand, taking into account how the change could influence both the operation as well as the structure of the grid (i.e., the building and retiring of capital assets, such as generators and transmission lines). It is therefore distinct from the more-commonly-known short-run marginal, which treat grid assets as fixed."[11] We consider this the appropriate emissions benchmark for calculating the effect of long-lived generating investments like solar photovoltaic panels.[12]

We use the EPA's Greenhouse Gas Equivalencies Calculator (EPA 2024) to compare the emissions savings to other sources.

Broader Economic Impacts

In addition to the savings for individual households, we also estimate impacts on solar installation jobs, permit fee revenue for jurisdictions, and jurisdiction staff time.

- **Jobs**
    - We start by calculating the baseline number of solar installation and project development jobs in the state. We estimate that this is 3,047 in 2024.
        - The calculation begins with data on the number of people in the state who spend the majority of their time working in the solar industry (IREC 2024). We focus on the subset employed in solar installation and project development.[13]
        - IREC also provides an estimate of employees working part-time in solar, but does not break this down by occupation. We assume that the same share of part-time workers are involved in installation & project development as majority-time workers, and that a part-time solar job is equivalent to half a majority-time solar job.
        - We add these figures together to produce an estimate of solar installation jobs. We then multiply this by 56%, the national share of solar installation jobs that are specifically targeting the residential market (IREC 2024).

[11] Description from https://www.nrel.gov/analysis/cambium.html.
[12] Note that many state electricity grids are part of larger, cross-state interconnections and regional transmission organizations, so the emissions intensity of the state's generating capacity may not be the same as the emissions intensity of the larger grid that the state participates in.
[13] This excludes manufacturing, wholesale trade & distribution, operations & maintenance, and an "other" category.

    - In the baseline scenario we assume that jobs increase proportionally with sales volumes.
    - In the smart permitting scenario, we model two countervailing effects shaping the demand for solar installation labor after smart permitting.
        - First, because smart permitting drives up demand for solar volumes above the baseline scenario, if the ratio of jobs to projects remained stable there would be a proportional increase in demand for solar installation labor.
        - Second, because smart permitting simplifies different parts of the solar installation firm business model, less labor hours are needed for each project. We use the fact that soft costs are primarily driven by labor to estimate the size of this effect. We calculate the ratio between total soft costs in the smart permitting and baseline scenarios, excluding any sales taxes or profits.
        - We multiply this ratio by the number of jobs that would be demanded if smart permitting increased sales volumes but labor needs per project remained constant.
    - The result is that although the labor hours needed for each project go down over time, the accompanying increase in volumes more than compensates, resulting in a projection of net job gains.
- **Jurisdiction Fee Revenue**
    - We assume that jurisdictions keep their permit fees stable.
    - We assume that jurisdictions cover the cost of using a permitting software platform. We set this cost to $35 in line with the pricing of SolarAPP+ (McAllister 2024).[14] This reduces the revenue from each project.
    - We compare the total fee revenue in the baseline scenario (where jurisdictions receive the full fee) with the revenue in the smart permitting scenario (where jurisdictions share some of the fee with the service provider).
    - Despite the assumption that jurisdictions now share some of their revenue with a smart permitting platform, at this price the increase in volume more than compensates for this choice.
- **Jurisdiction Staff Time Savings**
    - According to Cook et al. (2024) jurisdictions save between 25 and 60 minutes of staff time on average per permit after adopting SolarAPP+. We assume that as jurisdictions grow more comfortable with the system they will get the higher end of time savings, and so count savings as one hour for every project deployed in the smart permitting scenario (since

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[14] We use SolarAPP+ as a benchmark; other service providers may charge different prices for smart permitting.

by definition there are no time savings in the baseline scenario) to arrive at our estimate of staff time saved.

  - We assume that jurisdictions reassign relevant staff to other permitting issues rather than dismissing them.

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