Cost Containment, Retrospective Analysis, and Policy Feedback Loops
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In the midst of a global pandemic and crippling recession, cost containment and affordability concerns need to be top-of-mind when planning next steps for California's climate change policies. These programs should also be implemented in a way that mitigates—rather than exacerbates—social, economic, and environmental inequality. To meet these objectives, policy makers will need to anticipate what alternative policy options will cost and how those costs will be recovered.

Anticipating the costs and impacts of overlapping climate change policies is challenging. In principle, this exercise should get easier as California accumulates policy implementation experience. Notably, the state has already implemented some provisions that require retrospective analysis of existing climate policies. One important example is AB 398, which requires the Legislative Analyst's Office (LAO) to report annually on the economic impacts and benefits of California's greenhouse gas emissions targets.[1] Other mandates apply to specific programs. For example, the California Public Utilities Commission requirement (Pub. Util. Code § 913.3) requires the utilities to document the costs of complying with the Renewable Portfolio Standard.

These and other reporting obligations provide valuable insights into the real-world performance of the state's climate change policies. Ideally, there would be a coherent epistemic process through which these evidence-based insights could inform and induce policy course corrections. Although some of this potential is already being realized through regulatory proceedings and stakeholder engagements, these channels are limited and could be usefully expanded.

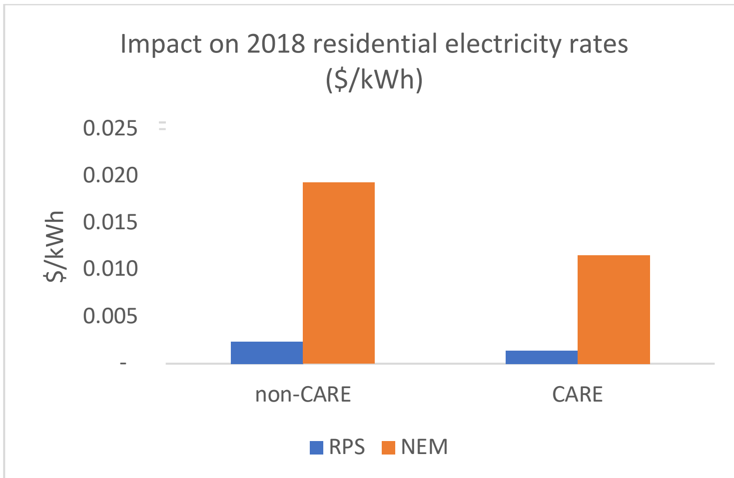
The accumulating evidence on California's renewable energy policies provides an important case in point. The annual report produced by the LAO provides an excellent overview of major policies currently in place to reduce GHG emissions from electricity generation in California (LAO, 2019). These include, but are not limited to, the statewide cap-and-trade program, the Renewable Portfolio Standard (RPS), and Net Energy Metering (NEM). Noting the absence of detailed retrospective evaluations of these important programs, LAO analysts construct back-of-the-envelope estimates of costs incurred per ton of CO2e reduced under these policies. Estimated costs of the RPS fall in the range of $60-$70 per ton, while estimated costs of rooftop solar policies fall in the range of $150-$200/ton (LAO, 2020).

It is important to assess not only what programs cost, but also who bears the costs of program implementation. For example, the RPS and NEM impact consumers' electricity bills in different ways. The above-market costs of complying with the RPS, which have been declining steadily over time, are passed through to all utility customers in electricity rates. Under net energy metering, however, NEM customers with rooftop PV systems avoid paying volumetric retail prices for the

[1] Cal. Health & Safety Code § 38592.6.

electricity they generate. Because substantial fixed costs are recovered via volumetric rates, NEM has the effect of shifting an increasing cost burden onto PV non-adopters.

The figure below summarizes back-of-the-envelope estimates of how these two renewable energy programs have increased retail electricity prices paid by customers of California's largest utility (PG&E) in 2019. Focusing on households that have not adopted rooftop solar PV systems, rate impacts are estimated for customers enrolled in the CARE program, and non-CARE customers, respectively. Details are summarized in the appendix.



The figure helps to illustrate how two policies designed to achieve similar objectives (in this case, accelerating investments in renewable energy) can have very different impacts in terms of cost incidence. Although renewable energy investments mandated under the RPS are significantly larger than those subsidized under NEM, the NEM program has had a much larger impact on retail electricity prices. This is because fixed costs—including transmission and distribution costs, wildfire adaptation costs, energy efficiency programs, and other system-wide investments—are recovered through volumetric prices ($/kWh). As more rooftop solar is added to the grid, these fixed costs must be recovered from a smaller base of utility retail sales (kWh). Customers who do not adopt rooftop solar, for whatever reason, are left paying more than their fair share of total system costs.

These summary calculations are meant to be approximate and illustrative. They look only at monetized costs and benefits, leaving out other important issues such as land use requirements. We are also mindful that decisions about the design of NEM policies is chiefly the responsibility of the Public Utilities Commission, rather than the Air Resources Board. Nevertheless, these calculations underscore the importance of considering both costs and cost incidence in the design and implementation of climate change policies. And when ex post assessments conclude that a policy is not working as intended, what is the process that translates these insights into policy course corrections?

Recommendations:

- We strongly endorse the LAO recommendation to direct agencies to facilitate more rigorous retrospective evaluation and, whenever possible, to design and implement programs in ways that can support robust evaluation (LAO, 2020).

- We urge the Board to consider not only the costs and emissions implications of existing and proposed policies, but also who pays these costs. Equity and affordability concerns should help guide policy instrument choice in future scoping plans.

- Important steps have already been taken to require retrospective reporting and analysis of policy outcomes. California is a climate policy incubator. Successes—and failures—demonstrated here hold lessons for not only California, but also other jurisdictions. These policy experiments will be more impactful if we can understand and export what policies are working and what approaches need refining. We encourage the Board to formalize a process through which insights from retrospective analysis can more directly inform prospective policy design/scoping.

References

LAO (2020). "Assessing California's Climate Policies—Electricity Generation". https://lao.ca.gov/reports/2020/4131/climate-policies-electricity-010320.pdf

Draft Appendix

These summary calculations are approximate, illustrative, and based on some work-in-progress by Severin Borenstein, Meredith Fowlie, and Jim Sallee.

Estimated impacts of the RPS on PG&E retail rates:

- The 2019 Padilla Report summarizes RPS and non-RPS procurement expenditures in terms of $/kWh. For PG&E these are $0.122 and $0.112/kWh, respectively.

- The AB67 Annual Report to the Legislature reports aggregate RPS revenue requirements by utility. PG&E reports $2,068,222,000.

  How much of this is "above market" cost? ($2,068,222,000/$.122) * .01 = $169,526,393.
- We assume that the share of the costs recovered from residential customers is proportional to the residential share of utility sales (34%) = $58,429,983

- Divide this across residential sales in 2018 implies an average retail price increase of $0.002/kWh.

Estimated impacts of NEM on PG&E retail rates:

- We use public data on NEM 2018 residential PV systems provided by the LBNL Tracking the Sun Report (https://emp.lbl.gov/tracking-the-sun).
- We use PV Watts to estimate the annual solar PV generation from these residential systems (approx. 3812 GWh).
- To compute residential kWh demand without NEM, we add this PV generation to residential sales: 3.151e+10 kWh
- To compute the residential revenue requirement without NEM, we increase the 2018 residential revenue requirement by the product of PV generation and our avoided cost estimate (7.43 cents/kWh). We estimate this counterfactual residential revenue requirement to be $6.024e+09.
- To estimate the counterfactual residential rate, divide the counterfactual revenue requirement by the counterfactual residential demand: $0.19/kWh.
- Contrast this with the observed average residential rate of $0.204/kWh to estimate an average retail price increase of approximately $0.014/kWh.

To compute CARE and non-CARE rates we assume a CARE subsidy of 40%. We assume that 28% of residential sales are to CARE customers.