Title: Additionality in Government Support for Renewable Electricity Development: Is the Sun Setting on Solar Support?

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Extended Abstract

Wind and solar have become among the lowest-cost sources of new electricity generation (Lazard, 2026). Yet governments continue to devote substantial public resources to accelerating their adoption. G20 countries, for example, provided upwards of $165 billion in funding for renewable power projects in 2023 alone (Laan et al., 2024). These interventions take many forms, including production subsidies, tax credits, long-term procurement contracts, and concessional financing. If renewable technologies are already cost-competitive, however, the efficiency case for such policies is not obvious (Borenstein, 2012). A central concern is whether public funds are paying for investment that would have occurred anyway. Evaluating these programs therefore requires knowing how many funded projects are additional, that is, how many would not have been built without government assistance. Growing constraints on climate finance budgets have made project additionality a critical consideration in allocating scarce public resources.

Despite the scale of government assistance for renewable projects, a key parameter for assessing additionality, the elasticity of renewable project development with respect to government support (the elasticity of additionality), remains poorly measured. Existing estimates come mostly from state- or country-level panels (Carley, 2009; Best and Burke, 2018) or studies of residential solar (Hughes and Podolefsky, 2015), with comparatively little evidence from utility-scale, project-level data. This uncertainty limits our ability to assess the cost-effectiveness of public spending on utility-scale renewables as a means of climate mitigation. This paper addresses that gap by estimating renewable project additionality in Canada. Using project-level data on utility-scale renewable investments between 2000 and 2025, we apply a bunching estimator to identify the elasticity of additionality. We then use these estimates to evaluate the fiscal implications of declining technology costs and tightening public resource constraints.

The elasticity of additionality determines subsidy efficiency and whether public funds finance additional capacity or are mere transfers to inframarginal projects. If the elasticity is close to one, development responds roughly in proportion to support and most public spending finances capacity that would not otherwise exist. If the elasticity is well below one, many supported projects are inframarginal and would have proceeded with less assistance or none. In this case, the fiscal cost per additional megawatt could far exceed the headline subsidy rate.

Estimating the additionality of public support for renewable projects faces three main obstacles. First, policy instruments are measured in different units. A feed-in tariff pays per megawatt-hour over a contract term, an investment tax credit covers a share of capital cost at commissioning,

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accelerated depreciation shifts the timing of tax payments, and carbon credits pay per tonne of avoided emissions at a fluctuating price. These tools are frequently part of the revenue or cost "stack" of proposed projects, and their value to developers depends on form as well as size (Johnston, 2019; Aldy et al., 2023). Comparing or combining these instruments requires converting each to a common metric. Second, although the availability of support is observable, whether a given project received it often is not. Program participation, contract prices, and tax positions are commercially confidential even for projects that move from proposal to operation. Third, and most fundamentally, project data are a selected sample. A project appears in the data only if it was built, and the decision to build depends on the support whose effect we seek to estimate.

Data and measurement

Through the Canadian Renewable Energy Association, we obtained a project-level dataset of 642 utility-scale wind, solar, and storage projects commissioned in Canada from 2000 through 2025, nearly the full population. Each project is linked to the federal and provincial instruments available for its province, technology, and commissioning year, producing a technology-location-year panel. To put instruments in common units, we build generic project finance models that convert each instrument into a present-value grant equivalent in dollars per megawatt and dollars per present-value megawatt-hour, by technology. The valuation rests on transparent assumptions about, among other factors, capital costs, capacity factors, contract duration, discounting, counterfactual electricity prices, and eligibility. All factors can be adjusted in sensitivity analysis.

To address selection, we apply two research designs. Our first approach uses a balanced province-year-technology panel that includes cells with and without development and relies on parametric assumptions. Province, year, and technology fixed effects absorb broad differences across places, periods, and technologies, so identification comes from provincial policy changes over time. Our second design combines the project finance framework with a local bankability-bunching estimator, adapting methods used to measure responses at tax kinks and notches (Kleven, 2016). For each province-year-technology cell, we construct a running variable equal to representative merchant value plus grant-equivalent support, less a capital-only levelized cost. This yields a standard net present value cut-off: a project is more likely to proceed once the index exceeds zero, the point at which it becomes financeable. The estimator compares build probabilities just below and above this threshold and measures the excess development that appears there.

Preliminary findings and policy implications

Preliminary evidence suggests the build probability rises from 29 percent just below the threshold to 49 percent just above it, giving an implied local elasticity of 0.73 and an additionality share of roughly 42 percent for projects near the financing margin. Merchant value, capital costs, and bandwidth are calibrated, so sensitivity analyses, including alternative merchant-value assumptions, are required. We obtain similar results with the fixed-effects estimation approach.

All results are preliminary, but we highlight three findings. First, development responds to support, but less than proportionally. Many projects receive inframarginal support. Second, responses differ by technology. Wind responds more to generation-linked support than solar does, even though solar received much larger support per unit of expected generation during the feed-in-tariff era

(Yatchew and Baziliauskas, 2011). Third, additionality has fallen sharply over time. Local bunching estimates decline from 59 percent in the 2000s to 48 percent in the 2010s and 15 percent in the 2020s. This pattern fits the economics of maturing technologies. As costs fall and more projects become viable unaided, a fixed support rate increasingly becomes an inframarginal transfer.

These initial results suggest three immediate policy implications. First, support should sunset as technologies mature. Our estimates can be used to guide sunsetting rates across technologies. Second, tools such as competitive procurement can preserve revenue certainty while reducing the rents created by instruments such as tax credits and administered prices (del Río and Linares, 2014). Third, support should be differentiated by technology and location, since the social value of a new megawatt depends on local resource quality, interconnection conditions, and the emissions displaced on the receiving grid (Callaway et al., 2018).

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