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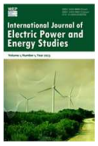

Energy, Flexibility or Adequacy? A Dual Decomposition of Investment Value in Multi-Stage Provincial Capacity Expansion

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ABSTRACT

Capacity-expansion studies increasingly add flexibility requirements, but a plan does not reveal whether an investment serves energy, flexibility or adequacy. This paper decomposes the value of every resource in a multi-stage capacity-expansion linear program of a three-zone province (2030–2040). The model couples hourly energy balances on representative days with a reserve requirement growing with wind and photovoltaic (PV) output, an adequacy margin, a carbon cap, heat-constrained coal units and energy-deliverable reserves, and every plan is re-evaluated on a full chronological year. Dual variables split each fleet's rent into energy volume, energy timing, reserve, adequacy, carbon and cost components, which sum to the investment cost by the zero-profit condition. In the base case, adequacy pays the full cost of open-cycle gas turbines and about half of the storage rent, energy timing most of the rest, and reserve less than 1%. Wind and PV variability appears as a timing discount of 13% and 22% of their energy value in 2040. The flexibility requirement raises the total cost by 0.09%, because capacity built for adequacy also holds reserve; without the adequacy margin it costs 0.7% and the plan sheds load in the full-year check.

KEYWORDS

Capacity Expansion Planning; Flexibility; Energy Storage; Resource Adequacy; Dual Decomposition.

1. INTRODUCTION

Provincial power systems in China are moving from coal-dominated generation to systems in which wind and solar supply most of the energy. Pathway studies for the provinces treat inter-provincial transmission and storage as central to this transition [1]. Planning studies of individual regions now co-optimize generation, networks, demand response and storage [2, 3], and generation expansion has been formulated with distributionally robust chance constraints on renewable output [4]. As the share of variable renewable energy (VRE) grows, a planner must procure three different services: *energy*, to meet demand over the year; *adequacy*, firm capacity at the peak; and *flexibility*, the ability to follow net-load ramps and to cover forecast errors with reserves. Many resources provide more than one of these services. A gas turbine built for the peak can also carry reserve; a battery shifts energy and can hold reserve as long as it has stored energy. The question of *what an investment is for* is therefore not answered by the investment plan itself.

Flexibility has been evaluated and planned in several ways. Flexibility metrics measure how likely the ramping resource is to fall short [5] or estimate the flexibility of a generation mix and embed it in unit construction and commitment [6]. Planning models with operational detail show that neglecting

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unit-commitment constraints can lead to capacity mixes that cannot meet demand, carbon and renewable targets at the same time [7], and that the level of temporal and operational detail changes the plans [8]. Tejada-Arango et al. show that representing power trajectories instead of hourly energy blocks, together with reserve deliverability, changes generation and storage expansion [9]. Adequacy and the effective use of thermal and tie-line capacity have been priced from a year of stochastic unit commitment in a multi-region system [10], and the storage energy needed for a net-zero grid has been quantified from cumulative energy mismatch [11]; related work sizes storage for very high renewable shares [12, 13]. Most directly related, Chen et al. derive power and ramp flexibility requirements from probabilistic net-load forecast errors and co-schedule energy and flexibility balance at three transition stages, with the stages as exogenous snapshots [14].

What pays for an investment is a classical question of power-system economics. Peak-load pricing shows that, at the optimum, capacity costs are recovered by the prices of the periods in which capacity is scarce [15, 16], and optimal spot prices recover the capital costs of an optimal generation mix [17]. Market-design studies build on this cost-recovery property: price caps and other imperfections leave peaking units with missing money that capacity mechanisms must supply [18, 19], and growing shares of VRE affect whether energy, reserve and capacity revenues suffice to recover generator costs [20]. On the VRE side, the market value of wind and PV falls as their share grows [21], and their integration costs have been split into profile, balancing and grid-related components [22, 23]. On the storage side, capacity-expansion studies find that the value of storage grows with the stringency of carbon constraints [24] and that its marginal value declines as more storage is deployed [25]. These studies price one service at a time or evaluate given portfolios; they do not decompose the investments of a multi-stage plan with explicit flexibility requirements into the services that pay for them.

Planning models must also represent the year with a few representative days. Time-series aggregation distorts storage that shifts energy between days unless the days are linked: Kotzur et al. link the storage state across the calendar days that the representative days stand for [26], and Tejada-Arango et al. use transition matrices between representative periods [27].

Three gaps remain. First, when flexibility requirements are added to planning, the result is a different plan, but the plan does not reveal which part of each investment is paid by energy, by flexibility or by adequacy; the counterfactual "plan without the requirement" mixes the three effects. Second, the energy dimension of flexibility is usually missing: reserves offered by storage and demand response are often treated as power headroom, although a battery can sustain a reserve only for as long as its stored energy lasts. Operational aggregation methods do account for the remaining horizon, e.g., reachable sets that keep the reported flexibility of multi-zone HVAC fleets deliverable [28] and reserve-oriented aggregation of DERs whose flexibility spans different time dimensions [29], but planning models seldom do. Among the studies above, [9] ties storage reserves to the state of charge through two-period constraints and [12] limits them by the storage level of the previous hour, whereas demand response is modelled without energy or payback limits in [14]. Third, the transition stages are rarely endogenous: [14] evaluates exogenous capacity snapshots, and pathway studies such as [1, 2] report how costs and curtailment change with flexibility measures but do not break the value of each resource down by service and stage.

This paper addresses these gaps with a multi-stage capacity-expansion linear program (LP) for a three-zone province and a dual-based decomposition of the value of every resource. The contributions are:

(1) A multi-stage expansion model that couples the hourly energy balance, a flexibility (reserve) balance whose requirement grows with the installed VRE capacity, and an adequacy constraint. Storage and demand response can offer reserve only if they can sustain it from stored energy for a given time, coal units that supply heat must run in the heating season, pumped-hydro storage is linked across all calendar days of the year, and every plan is re-evaluated in a full-year chronological simulation.

(2) A decomposition of each resource's net revenue into energy, reserve, adequacy and carbon components from the LP duals, with the energy component split into a volume part and a timing part, so that flexibility that is paid through energy prices is separated from flexibility that is paid through reserve. Because the model is linear, the components of every expanded technology add up to its investment cost (zero-profit condition), which we verify numerically for all expansions; the decomposition therefore states what each investment is paid for.

(3) Numerical evidence on a stylized provincial system over 2030, 2035 and 2040: flexible resources are paid mainly through adequacy and the timing of energy, and reserve pays less than 1% of the 2040 battery rent; at the base requirement, the flexibility balance costs 0.09% of the total cost as long as adequacy is procured with a planning margin, because capacity built for adequacy also holds reserve, but 0.7% without the margin, and up to 4.8% at three times the base requirement; and heat-constrained coal units and the choice of representative days change the plan more than the reserve rules do.

Section 2 presents the model, Section 3 the value decomposition, Section 4 the test system and results, Section 5 the limitations, and Section 6 concludes.

2. MULTI-STAGE PLANNING MODEL

This section introduces the structure and notation of the model, the investment decisions, the operation on representative days, the adequacy and carbon constraints, and the full-year re-evaluation of each plan.

2.1. Structure and Notation

The province has zones $z \in \mathcal{Z}$ connected by corridors $l \in \mathcal{L}$ (transport model). Investments are decided at stages $s \in \mathcal{S}$, each of which stands for Y_s consecutive years; capacity built at stage s remains available at all later stages of the horizon. Operation at stage s is represented by representative days $k \in \mathcal{K}$ with weights w_k (days per year) and hours $t \in \mathcal{T}$. With discount rate r, the present value of one unit paid in every year of stage s is $\phi_s = \sum_{y \in y_s}(1+r)^{-y}$, and operating costs of stage s are weighted by $\phi_s w_k$. Units are GW, GWh and million dollars (M$). Technologies are thermal ($j \in \mathcal{J}^{\mathrm{th}}$: coal, combined-cycle gas turbines CCGT, open-cycle gas turbines OCGT), variable renewable ($j \in \mathcal{J}^{\mathrm{vre}}$: wind, PV), storage ($e \in \mathcal{J}^{\mathrm{st}}$: batteries, pumped hydro PHS) and demand response (DR).

2.2. Investment

Let $\bar{C}_{jzs}$ be the capacity of technology j in zone z at stage s, $\bar{C}^0_{jzs}$ its existing capacity (with exogenous coal retirement) and $n_{jzq} \geq 0$ the capacity built at stage q:

$$\bar{C}_{jzs} = \bar{C}^0_{jzs} + \sum_{q \leq s} n_{jzq}. \tag{1}$$

Storage has separate power and energy capacities $\bar{P}_{ezs}, \bar{E}_{ezs}$ with new builds whose duration lies in $[\underline{d}_e, \overline{d}_e]$; DR capacity is limited to a share of the zonal peak, and corridor capacities $\bar{F}_{ls}$ follow (1). The investment cost is

$$C^{\mathrm{inv}} = \sum_s \Big(\sum_{q \geq s} \phi_q\Big)\Big[\sum_{j,z}(a_j + o_j) n_{jzs} + \sum_{e,z}(a^{\mathrm{P}}_e n^{\mathrm{P}}_{ezs} + a^{\mathrm{E}}_e n^{\mathrm{E}}_{ezs}) + \sum_z a^{\mathrm{dr}} n^{\mathrm{dr}}_{zs} + \sum_l a^{\mathrm{f}}_l n^{\mathrm{f}}_{ls}\Big], \tag{2}$$

with annualized capital costs a and fixed operation and maintenance costs o paid from the stage of construction to the end of the horizon.

2.3. Operation on Representative Days

All operating variables carry the indices (s, k, t), which we omit where no confusion arises; the previous hour of $t = 1$ is hour T of the same representative day.

2.3.1. Thermal Units

Each technology-zone fleet is a clustered unit with online capacity u_{jz}, output p_{jz}, start-ups v_{jz} and upward and downward reserves $r^{\uparrow}_{jz}, r^{\downarrow}_{jz}$ [7]:

$$u_{jz} \le \bar{C}_{jzs}, \quad p_{jz} + r^{\uparrow}_{jz} \le u_{jz}, \quad p_{jz} - r^{\downarrow}_{jz} \ge \underline{\pi}_j u_{jz}, \quad r^{\uparrow}_{jz}, r^{\downarrow}_{jz} \le \varsigma_j u_{jz}, \tag{3}$$

$$p_{jz,t} - p_{jz,t-1} \le \rho_j u_{jz,t}, \qquad p_{jz,t-1} - p_{jz,t} \le \rho_j u_{jz,t-1}, \qquad v_{jz,t} \ge u_{jz,t} - u_{jz,t-1}, \tag{4}$$

where $\underline{\pi}_j$ is the minimum stable level, ς_j the share of online capacity deliverable within the reserve activation time, and ρ_j the hourly ramp rate. The operating cost is $c^{\mathrm{v}}_j p_{jz} + c^{\mathrm{nl}}_j u_{jz} + c^{\mathrm{su}}_j v_{jz}$ (variable, no-load and start-up costs). On representative days of the heating season, a share χ_z of the coal capacity of zone z supplies heat and must run: $u_{\mathrm{coal},z} \ge \chi_z \bar{C}_{\mathrm{coal},zs}$ and $p_{\mathrm{coal},z} \ge \underline{\pi}^{\mathrm{chp}} \chi_z \bar{C}_{\mathrm{coal},zs}$.

2.3.2. Variable Renewables

$0 \le p_{jz} \le \alpha_{jz} \bar{C}_{jzs}$ with the hourly capacity factor α_{jz}; curtailment is free, and a VRE plant can offer downward reserve $r^{\downarrow}_{jz} \le p_{jz}$ by reducing its output.

2.3.3. Storage

With charge c_{ez}, discharge d_{ez}, efficiency η_e (each way) and state of charge σ_{ez}:

$$c_{ez}, d_{ez} \le \bar{P}_{ezs}, \qquad r^{\uparrow}_{ez} + d_{ez} - c_{ez} \le \bar{P}_{ezs}, \qquad r^{\downarrow}_{ez} + c_{ez} - d_{ez} \le \bar{P}_{ezs}, \tag{5}$$

$$\sigma_{ez,t} = \sigma_{ez,t-1} + \eta_e c_{ez,t} - d_{ez,t}/\eta_e, \qquad 0 \le \sigma_{ez,t} \le \bar{E}_{ezs}, \tag{6}$$

$$\sigma_{ez,t} - \frac{\Delta}{\eta_e} r^{\uparrow}_{ez,t} \ge 0, \qquad \sigma_{ez,t} + \Delta \eta_e r^{\downarrow}_{ez,t} \le \bar{E}_{ezs}. \tag{7}$$

Constraint (7) makes reserves *energy-deliverable*: after any hour, the storage can sustain its upward (downward) reserve for Δ hours from the energy it holds (the space it has left). Without (7), reserves are limited only by the power headroom (5). Batteries are periodic within each representative day ($\sigma_{ez,T}$ equals the initial state, which is a variable). A throughput cost $c^{\mathrm{st}}(c_{ez} + d_{ez})$ applies.

2.3.4. Linked Pumped-hydro Storage

PHS shifts energy between days, which periodic representative days cannot represent. Following [26], we write the PHS state on representative day k relative to the start of the day, $\sigma^{\mathrm{rel}}_{k,t}$, and introduce

the state $S_\tau \geq 0$ at the start of every calendar day $\tau = 1, \ldots, 365$, with $k(\tau)$ the representative day of τ:

$$S_{\tau+1} = S_\tau + \sigma^{\mathrm{rel}}_{k(\tau),T}, \qquad S_{366} = S_1, \qquad S_\tau + \underline{\sigma}_{k(\tau)} \geq 0, \qquad S_\tau + \overline{\sigma}_{k(\tau)} \leq \bar{E}, \tag{8}$$

where $\underline{\sigma}_k \leq \min\{0, \min_t(\sigma^{\mathrm{rel}}_{k,t} - \Delta r^{\uparrow}_{k,t}/\eta)\}$ and $\overline{\sigma}_k \geq \max\{0, \max_t(\sigma^{\mathrm{rel}}_{k,t} + \Delta\eta r^{\downarrow}_{k,t})\}$ are auxiliary variables, so that (8) enforces the limits of (6)–(7) on every calendar day.

2.3.5. Demand Response

Load reduction δ_z is paid back within the day (b_z with $\sum_t \delta_{z,t} = \sum_t b_{z,t}$), both limited by the DR capacity. DR can hold upward reserve $r^{\uparrow}_z$ with $\delta_z + r^{\uparrow}_z \leq \bar{C}^{\mathrm{dr}}_{zs}$ and, when reserves must be energy-deliverable, $\sum_{\tau \leq t} \delta_{z,\tau} + \Delta r^{\uparrow}_{z,t} \leq H^{\mathrm{dr}} \bar{C}^{\mathrm{dr}}_{zs}$ (otherwise $\sum_{\tau \leq t} \delta_{z,\tau} \leq H^{\mathrm{dr}} \bar{C}^{\mathrm{dr}}_{zs}$), where H^{dr} is the daily energy limit in hours of capacity. Curtailed load costs c^{dr} per MWh.

2.3.6. Balances

For every zone and hour, with corridor flows $|f_l| \leq \bar{F}_{ls}$ and load L_z,

$$\sum_j p_{jz} + \sum_e (d_{ez} - c_{ez}) + \delta_z - b_z + \sum_l A_{zl} f_l + q_z = L_z \qquad (\lambda_{zskt}), \tag{9}$$

where A is the zone–corridor incidence matrix and $q_z \geq 0$ is unserved energy at the value of lost load. The province-wide flexibility balance requires, for every hour,

$$\sum_{\mathrm{all}} r^{\uparrow} \geq \epsilon^{\uparrow}_{\mathrm{L}} \sum_z L_z + \sum_z \left(\epsilon^{\uparrow}_{\mathrm{w}} \alpha_{\mathrm{wz}} \bar{C}_{\mathrm{wzs}} + \epsilon^{\uparrow}_{\mathrm{pv}} \alpha_{\mathrm{pvz}} \bar{C}_{\mathrm{pvzs}} \right) \qquad (\psi^{\uparrow}_{skt}), \tag{10}$$

$$\sum_{\mathrm{all}} r^{\downarrow} \geq \epsilon^{\downarrow}_{\mathrm{L}} \sum_z L_z + \epsilon^{\downarrow}_{\mathrm{vre}} \sum_z \left(\alpha_{\mathrm{wz}} \bar{C}_{\mathrm{wzs}} + \alpha_{\mathrm{pv}}\ \bar{C}_{\mathrm{pvzs}} \right) \qquad (\psi^{\downarrow}_{skt}), \tag{11}$$

so the requirement grows with the load and with the VRE output that is available (forecast errors scale with it), and it is linear in the capacities.

2.4. Adequacy, Carbon and Objective

At every stage, the firm capacity must exceed the peak load by the planning reserve margin m:

$$\sum_{j,z} \kappa_j \bar{C}_{jzs} + \sum_{e,z} 0.95 \min\{\bar{P}_{ezs}, \bar{E}_{ezs}/4\} + 0.9 \sum_z \bar{C}^{\mathrm{dr}}_{zs} \geq (1+m) L^{\mathrm{peak}}_s \qquad (\mu_s), \tag{12}$$

where κ_j is the capacity credit (the minimum is written with an auxiliary variable). Annual emissions are capped: $\sum_{j,z,k,t} w_k \gamma_j p_{jzskt} \leq \overline{\mathrm{CO}_2}_s$ (τ_s). The planner minimizes C^{inv} plus the present value of all operating costs, including unserved energy. The model is an LP; the symbols in parentheses denote the dual variables used in Section 3.

2.5. Full-year Chronological Re-evaluation

A plan found on representative days is re-evaluated with its capacities fixed on all 365 days of each stage in chronological order: the state of every storage device and the thermal ramp and commitment variables carry over from one day to the next, and the flexibility balance (10)–(11) is kept with a penalty on any shortfall. This check measures, for each plan, the reserve shortfall and the operating cost that the representative days do not see.

3. WHAT PAYS FOR EACH INVESTMENT: A DUAL DECOMPOSITION

This section derives the revenue components of each fleet from the duals of the planning LP, shows that they repay the investment cost, and defines the counterfactual plans that complement the decomposition.

3.1. Revenue Components

Let λ_{zskt}, $\psi^{\uparrow}_{skt}$, $\psi^{\downarrow}_{skt} \geq 0$, $\mu_s \geq 0$ and $\tau_s \leq 0$ be the optimal duals of the energy balance (9), the flexibility balance (10)–(11), the adequacy constraint (12) and the carbon cap. Because the operating costs in the objective are weighted by $\phi_s w_k$, these duals are already present values. For a fleet (j,z) at stage s we define its components

$$\begin{aligned} R^{\mathrm{E}}_{jzs} &= \textstyle\sum_{k,t} \lambda_{zskt}\, g_{jzskt}\,, & R^{\mathrm{F}}_{jzs} &= \textstyle\sum_{k,t}\big(\psi^{\uparrow}_{skt} r^{\uparrow}_{jzskt} + \psi^{\downarrow}_{skt} r^{\downarrow}_{jzskt}\big)\,, \\ R^{\mathrm{A}}_{jzs} &= \mu_s\, \kappa_j \bar{C}_{jzs}, & R^{\mathrm{C}}_{jzs} &= \tau_s \textstyle\sum_{k,t} w_k \gamma_j p_{jzskt}\,, \end{aligned} \tag{13}$$

where g is the fleet's net injection (p for generators, $d-c$ for storage, $\delta-b$ for DR). Two further terms complete the account: the variable, no-load, start-up, throughput and DR costs $R^{\mathrm{V}}_{jzs} \leq 0$, and, for wind and PV, the *requirement charge*

$$R^{\mathrm{Q}}_{jzs} = -\textstyle\sum_{k,t}\big(\psi^{\uparrow}_{skt}\epsilon^{\uparrow}_{j} + \psi^{\downarrow}_{skt}\epsilon^{\downarrow}_{\mathrm{vre}}\big)\alpha_{jzkt}\bar{C}_{jzs} \leq 0, \tag{14}$$

the value of the reserve that the fleet's own forecast errors require. The rent of the fleet is $R_{jzs} = R^{\mathrm{E}} + R^{\mathrm{F}} + R^{\mathrm{A}} + R^{\mathrm{C}} + R^{\mathrm{V}} + R^{\mathrm{Q}}$.

Flexibility is valued not only through reserves but also through the timing of energy. We therefore split the energy component into a *volume* part at the time-weighted average price $\bar{\lambda}_{zs}$ of the zone and stage and a *timing* (shape) part,

$$R^{\mathrm{E}}_{jzs} = \underbrace{\bar{\lambda}_{zs} \textstyle\sum_{k,t} \phi_s w_k\, g_{jzskt}}_{R^{\mathrm{vol}}_{jzs}} + \underbrace{\textstyle\sum_{k,t}\big(\lambda_{zskt} - \phi_s w_k \bar{\lambda}_{zs}\big) g_{jzskt}}_{R^{\mathrm{tim}}_{jzs}}\,, \qquad \bar{\lambda}_{zs} = \frac{\sum_{k,t}\lambda_{zskt}}{\phi_s\, T \sum_k w_k}. \tag{15}$$

R^{tim} is positive for a resource that produces when energy is expensive and consumes when it is cheap (storage, DR) and negative for a resource whose output depresses the prices of the hours in which it produces, which is the profile or cannibalization effect known for wind and PV [21]; in the terminology of integration costs, $-R^{\mathrm{tim}}$ of wind and PV corresponds to their profile cost [22, 23]. We call $R^{\mathrm{F}} + R^{\mathrm{Q}}$ the *reserve value* and R^{tim} the *timing value*; both are values of flexibility.

3.2. Zero-profit Condition

Proposition 1. *If a technology j is expanded in zone z at stage s ($n_{jzs} > 0$) in an optimal solution of the planning LP, then*

$$(a_j + o_j) \sum_{q \geq s} \phi_q = \sum_{q \geq s} \frac{R_{jzq}}{\bar{C}_{jzq}}, \tag{16}$$

that is, the rents per unit of capacity collected from the stage of construction to the end of the horizon exactly repay the investment. For an existing fleet that is not expanded, the right-hand side is at most the left-hand side evaluated at the stage in question (no profitable expansion is left).

Proof. The capacity $\bar{C}_{jzq}$ enters the operating constraints (3) (or the availability limit of VRE), the adequacy constraint (12) and, for VRE, the requirements (10)–(11). Stationarity of the Lagrangian with respect to $n_{jzs} > 0$ gives $(a_j + o_j) \sum_{q \geq s} \phi_q = \sum_{q \geq s} (\beta_{jzq} + \mu_q \kappa_j + \partial_{\bar{C}} \mathcal{L}^{\mathrm{Q}}_{jzq})$, where β_{jzq} collects the duals of the capacity limits. Complementary slackness applied to the operating constraints of a fleet that is linear in its capacity (all constraints of (3)–(4) and the VRE limit are homogeneous of degree one in $(\bar{C}, u, p, v, r)$) shows that $\beta_{jzq} \bar{C}_{jzq}$ equals the fleet's operating margin $R^{\mathrm{E}} + R^{\mathrm{F}} + R^{\mathrm{C}} + R^{\mathrm{V}}$. Dividing by $\bar{C}_{jzq}$ and adding the adequacy and requirement terms gives (16). The second statement is dual feasibility for $n_{jzq} \geq 0$. □

Proposition 1 is the multi-stage, multi-service form of the cost-recovery property of peak-load pricing [15–17], and it is what makes the decomposition meaningful: the shares R^{E}/R, R^{F}/R and R^{A}/R of a fleet that is being expanded are the shares of its investment cost that are paid by energy, by flexibility and by adequacy. We check (16) numerically for every expansion in Section 4. Storage has separate power and energy capacities; the same argument applies to the pair $(\bar{P}, \bar{E})$ jointly, and we report its rent per unit of power capacity. DR capacity is additionally limited by its potential, so DR can earn more than its cost when that limit binds.

3.3. Counterfactual Plans

The decomposition explains one plan. We complement it with counterfactual plans that differ in one modelling choice and are all re-evaluated in the full-year chronological simulation of Section 2:

- *energy-only*: no flexibility balance (10)–(11);
- *power-only reserves*: the flexibility balance without the energy-deliverability constraints (7) and without the DR energy limit on reserve;
- *unlinked PHS*: pumped hydro periodic within each representative day instead of (8);
- *no adequacy constraint*: (12) removed, so that firm capacity is procured only through scarcity in the energy and reserve balances.

The difference between the total costs of a counterfactual plan and of the base plan, both evaluated on the full year under the same flexibility requirement, is the cost of the omitted modelling element.

4. CASE STUDY

This section describes the stylized province, checks the zero-profit condition for the base plan, decomposes the rents, and compares counterfactual plans and flexibility requirements.

4.1. A Stylized Three-zone Province

The province has a wind-rich north (N, 30% of the load), a central load centre (C, 50%) and a solar-rich south (S, 20%) with pumped-hydro sites. The peak load grows from 40 GW in 2030 to 44 and 48.5 GW in 2035 and 2040, and the carbon cap falls from 150 to 105 and 60 Mt/yr. One year of hourly load, wind and PV profiles per zone is synthetic but has the features that matter for flexibility: winter and summer load peaks with an evening daily peak and lower weekend load; wind driven by correlated synoptic regimes that persist for days; and PV with seasonal day length and correlated cloudiness. Annual capacity factors are 0.26–0.34 for wind and 0.16–0.19 for PV, and the load factor is about 0.70. Ten representative days are selected by k-medoids clustering of the normalized daily profiles, with the day of the highest net load always kept; the weights are the numbers of days each medoid represents.

The existing fleet in 2030 has 28 GW of coal, retiring to 22 and 14 GW in 2035 and 2040, 4 GW of CCGT, 12 GW of wind, 10 GW of PV and 3 GW / 24 GWh of pumped hydro, and 15 GW of transmission between the zones. In the heating season (November to mid-March) half of the northern and 30% of the central coal capacity is combined heat and power that must stay online at no less than 60% of its capacity, the heat-driven inflexibility that is known to cause wind curtailment in northern China [30]. Renewable heating systems, for which regional decision frameworks exist [31], would relax this constraint but are not modelled. Table 1 lists the technology parameters. All monetary values are illustrative and chosen within plausible ranges; the conclusions concern mechanisms and relative magnitudes rather than a specific province.

Table 1. Technology parameters

	Capital	Fixed O&M	Variable	No-load	CO_2	Min. stable	Ramp	Reserve
	\$/kW-yr	\$/kW-yr	\$/MWh	\$/MW-h	t/MWh	share	share/h	share
Coal (existing)	–	–	32	4	0.85	0.40	0.25	0.05
CCGT	62	22	58	6	0.37	0.35	0.60	0.10
OCGT	40	12	95	10	0.55	0.25	1.00	0.20
Wind	95	–	0	–	0	–	–	–
PV	55	–	0	–	0	–	–	–
	Power / energy cost		Efficiency	Duration (h)		Other		
Battery	18 \$/kW-yr / 16 \$/kWh-yr		0.93 each way	1–8		all zones		
Pumped hydro	70 \$/kW-yr / 4 \$/kWh-yr		0.87 each way	6–24		zone S, linked days		
DR	30 \$/kW-yr		150 \$/MWh	4 h/day		N, C; ≤6% of peak		

Note: Capital costs are annualized; reserve share is the part of online capacity deliverable within the activation time. Start-up costs: coal 40, CCGT 25, OCGT 5 \$/MW. Capacity credit: thermal 0.95, wind 0.10, PV 0.02, storage $0.95 \min\{\bar{P}, \bar{E}/4\}$, DR 0.9; planning margin 12%. Reserve requirement: upward 3% of the load $+$ 12% of the available wind $+$ 10% of the available PV output; downward 2% of the load $+$ 5% of the available VRE output; $\Delta = 2$ h. Corridors: N–C 8 GW (60 \$/kW-yr for expansion), S–C 5 GW (70), N–S 2 GW (90). Discount rate 6%; value of lost load 10,000 \$/MWh.

4.2. Base Plan and Zero-profit Check

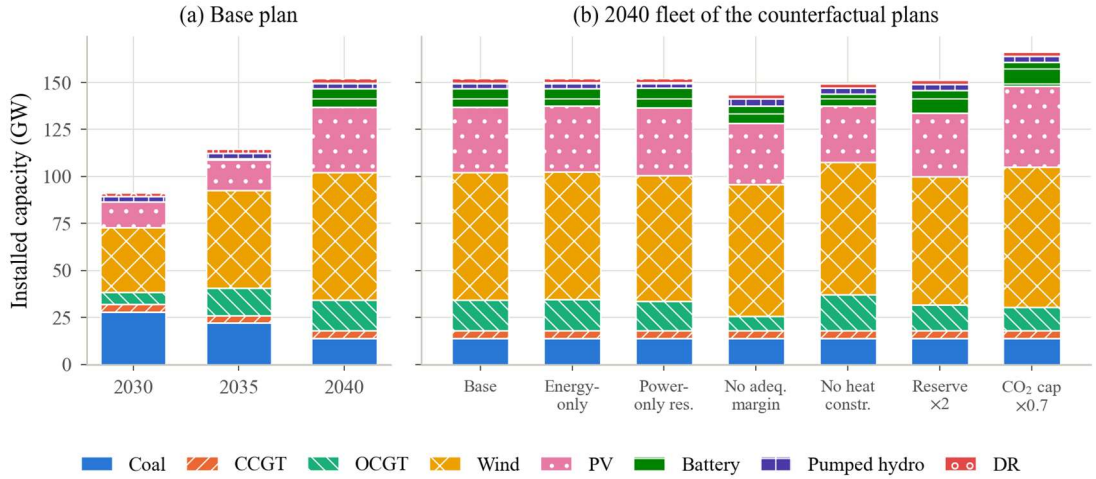

Figure 1. Installed capacity: (a) base plan by stage; (b) 2040 fleet of the base plan and of the counterfactual plans of Section 3

Table 2. Zero-profit check for the base plan

Technology	Zone	Stage	Built (GW)	Cost	Rent
OCGT	N	2030	6.44	535.3	535.3
Wind	N	2030	12.77	978.0	978.0
Wind	S	2030	9.59	978.0	978.0
PV	S	2030	3.62	566.2	566.2
DR	N	2030	0.72	308.8	593.8
DR	C	2030	1.20	308.8	593.8
OCGT	N	2035	0.66	303.2	303.2
OCGT	C	2035	3.01	303.2	303.2
OCGT	S	2035	4.43	303.2	303.2
Wind	N	2035	13.55	553.8	553.8
Wind	S	2035	4.17	553.8	553.8
PV	C	2035	0.47	320.6	320.6
PV	S	2035	2.14	320.6	320.6
DR	N	2035	0.07	174.9	352.7
DR	C	2035	0.12	174.9	352.7
OCGT	N	2040	1.81	129.7	129.7
Wind	N	2040	7.32	236.9	236.9
Wind	S	2040	8.32	236.9	236.9
PV	C	2040	18.69	137.1	137.1
DR	N	2040	0.08	74.8	144.5
DR	C	2040	0.14	74.8	144.5
Battery fleet*	N	from 2035	2.13	273.7	273.7
Battery fleet*	C	from 2040	5.57	204.4	204.4
Battery fleet*	S	from 2040	2.06	204.4	204.4

Note: Investment cost and rent collected from the stage of construction to the end of the horizon (present values, M$/GW). *Fleet-level check per GW of fleet power capacity.

Figure 1a shows the base plan. Wind grows from 34.4 GW in 2030 to 52.1 and 67.7 GW, PV from 13.6 to 16.2 and 34.9 GW, and OCGT capacity from 6.4 to 14.5 and 16.3 GW, which replaces most of the retiring coal as firm capacity. Batteries enter in 2035 (0.6 GW) and reach 9.8 GW with 39.0 GWh (4 h) in 2040; DR is built up to its potential in every stage (2.3 GW in 2040). Emissions are 114, 93 and 60 Mt/yr, so the carbon cap binds only in 2040, at a carbon price of 9.7 \$/t. The average energy price rises from 35.3 to 41.6 \$/MWh, while the price of upward reserve stays at 0.5–1.5 \$/MW-h and downward reserve is never scarce.

Table 2 verifies Proposition 1 for all 21 generation and DR expansions and, at fleet level, for the three battery fleets (for storage, the discounted investment cost of the whole fleet equals its discounted rent, because power and energy capacity are built in different proportions at different stages). For generation and storage, cost and rent agree to within 3×10^{-13} M\$/GW. DR collects about twice its cost because its potential limit binds, as noted after Proposition 1. The identity also explains the adequacy price. An OCGT earns almost nothing from energy and reserve, so its adequacy component alone must repay its annualized cost of 52 \$/kW-yr; the price of firm capacity is therefore $52/0.95 = 54.7$ \$/kW-yr in every stage, and every resource with a capacity credit of 0.95 collects 52 \$/kW-yr from it.

4.3. What Pays for Each Investment

Figure 2 decomposes the rent of each technology per kilowatt-year of capacity (batteries are not built in 2030). Three results stand out.

Firm capacity is paid for by adequacy. The adequacy component covers the full cost of OCGT in every stage; its energy volume and timing components (3.5 and 5.9 \$/kW-yr in 2040) only offset its variable and carbon costs. DR is paid 79–91% by adequacy and 9–21% by reserve.

Flexibility is paid for through energy timing, not through reserve. The timing component of storage grows with the share of VRE: for pumped hydro it rises from 20% of the positive rent in 2030 to 29% in 2035 and 50% in 2040, and for batteries from 36% in 2035 to 44% in 2040. The rest of the storage rent is adequacy (49–78%); the reserve component is 12% of the battery rent in 2035 and 0.5% in 2040. The negative energy-volume component of storage is the cost of its conversion losses.

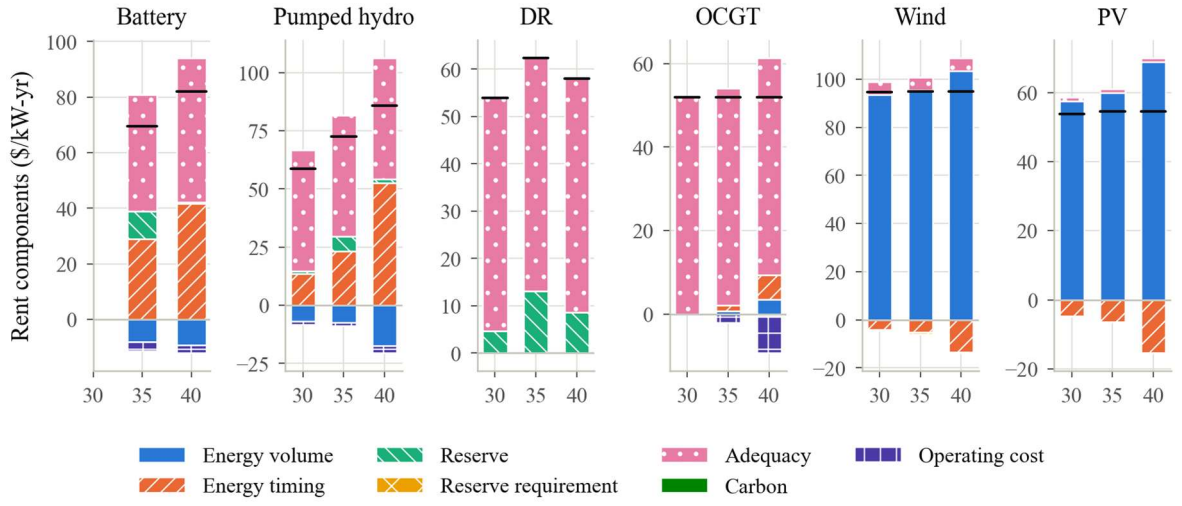

Figure 2. Rent components per kilowatt-year of capacity in 2030, 2035 and 2040 (base plan; the black bar marks the net rent)

VRE pays for its own variability through the timing discount. The timing component of wind is -4.1, -5.2 and -13.6 \$/kW-yr in the three stages (4%, 5% and 13% of its volume value), and that of PV -4.7, -6.4 and -15.5 \$/kW-yr (8%, 11% and 22%). The requirement charge (14) is below 1 \$/kW-yr. Hence the cost of the variability of wind and PV appears almost entirely as the lower value of the energy they produce, which is the revenue that storage collects as timing value.

These shares are robust to the model variants of Table 3: across the plans with 6, 10 and 16 representative days, with power-only reserves, unlinked pumped hydro, 1.5 times the reserve requirement and a 30% tighter carbon cap, the 2040 battery rent is 42–45% timing, 0–2% reserve and 55–56% adequacy.

4.4. Counterfactual Plans

Table 3 compares the counterfactual plans of Section 3 and the sensitivity cases, and Figure 1b shows their 2040 fleets. The last four columns re-evaluate the 2040 fleet on the full chronological year under the base flexibility requirement.

Table 3. Counterfactual and sensitivity plans

	Objective		2040 capacity					Full-year check, 2040			
Plan	bn$	Δ%	OCGT	Bat.	Bat. E	Wind	PV	Op. cost	Rep. err. %	Short.	Unserved
Base plan	93.1	0.00	16.3	9.8	39.0	67.7	34.9	2809	+3.5	0.0	0.00
Energy-only	93.0	-0.09	16.7	9.4	37.4	67.7	35.0	2812	+3.3	0.0	0.00
Power-only reserves	93.1	-0.02	15.7	10.5	42.0	67.0	35.9	2799	+3.5	0.0	0.00
Unlinked PHS	93.1	0.00	16.4	9.7	38.9	67.7	35.0	2809	+3.5	0.0	0.00
No adequacy margin	88.4	-5.02	7.8	9.3	21.9	70.0	32.6	2876	+2.5	4.9	0.74
No heat-constrained coal	92.6	-0.52	19.3	6.7	26.6	70.4	29.7	2873	+3.2	0.0	0.00
Reserve ×0.5	93.0	-0.09	16.7	9.4	37.5	67.7	35.0	–	–	–	–
Reserve ×1.5	93.4	+0.26	15.6	10.4	41.7	68.4	33.5	–	–	–	–
Reserve ×2	93.7	+0.63	13.8	12.3	49.2	68.1	33.8	–	–	–	–
Carbon cap ×0.7	94.0	+0.95	12.5	12.7	50.9	74.7	43.0	–	–	–	–
6 rep. days	92.3	-0.93	17.0	9.8	37.4	64.5	39.0	2927	-1.1	0.0	0.00
16 rep. days	90.2	-3.13	19.0	6.9	27.6	71.0	26.1	3089	-9.1	0.0	0.00

Note: Objective in billion \$ (present value) and its change relative to the base plan; 2040 capacities in GW (battery energy in GWh); DR is at its potential of 2.3 GW in every plan. Full-year check of the 2040 fleet: annual operating cost (M\$/yr), error of the representative-day estimate of that cost, upward reserve shortfall and unserved energy (GWh/yr).

Energy-only. Removing the flexibility balance lowers the objective by only 0.09% and changes the 2040 fleet by 0.4 GW of batteries and 0.4 GW of OCGT. Operated for a full year under the flexibility requirement, the energy-only fleet has no reserve shortfall and a 0.1% higher operating cost than the base fleet (2,812 against 2,809 M\$/yr). The reserve requirement is met by capacity that is built for energy and adequacy anyway: committed thermal units, storage and DR.

Power-only reserves. Without energy deliverability, the plan builds 0.7 GW more battery power and 0.6 GW less OCGT, because a battery can then offer its full power as reserve regardless of its state of charge. This fleet also passes the full-year check with the deliverability rules, so in this system the rule changes the composition of the fleet but not its reliability.

Unlinked pumped hydro. Periodic pumped-hydro operation within each representative day changes the objective by less than 0.01%: the 8-hour plant is used mainly for shifting within the day, and inter-day shifting has little value in this system.

No adequacy margin. Without (12), the objective falls by 5.0%, OCGT capacity by 8.5 GW and battery energy from 39.0 to 21.9 GWh. The representative days do not reveal the problem, but the full-year check does: the 2040 fleet misses 4.9 GWh of upward reserve in 3 h and cannot serve 0.74 GWh of load. The price of upward reserve rises to 3.4–4.7 $/MW-h, three to seven times the base values, and the battery rent becomes 96% timing and 4% reserve.

No heat constraint. Without must-run CHP units, 3.1 GW less battery power and 5.2 GW less PV are built, and 2.7 GW more wind and 3.0 GW more OCGT. This is consistent with must-run coal output at night in the heating season lowering the value of wind, whose output peaks at night, and raising that of storage.

Reserve requirement and carbon cap. Half the reserve requirement gives the energy-only plan; 1.5 and 2 times the requirement raise the objective by 0.26% and 0.63% and shift about 0.7 and 2.5 GW from OCGT to batteries. A 30% tighter carbon cap raises the objective by 0.95% and adds 7.0 GW of wind, 8.1 GW of PV and 2.9 GW of batteries.

Representative days. The number of representative days changes the plan more than the flexibility requirement does. With 16 days, 2.9 GW less battery power and 8.8 GW less PV are built; the full-year operating cost of this fleet in 2040 is 10% higher than that of the base fleet, and its representative days underestimate it by 9.1%, against an overestimate of 3.5% for the 10 base days and an underestimate of 1.1% for 6 days. The representation of time is known to affect planning results [8, 26]; here, the error of the k-medoids selection with one extreme day is not even monotonic in the number of days. The rent shares of the previous subsection are nevertheless the same for all three selections.

4.5. When Does Flexibility Pay?

Figure 3 repeats the comparison between the plan with and without the flexibility balance for reserve requirements of one to three times the base values, with the base and a 40% tighter carbon cap, and with and without the adequacy margin.

With the adequacy margin, the flexibility requirement costs 0.09–0.10% of the total cost at the base scale, 0.72–0.80% at twice and 1.55–1.82% at three times the base requirement. The reserve share of the 2040 battery rent grows from 0% to 9–16%, and the timing share falls from 44–45% to 33–34%. Without the adequacy margin, the same requirements cost 0.69–0.71%, 1.69–2.38% and 3.11–4.84%, and the reserve share of the battery rent grows from 4–7% to 26–36%. The tighter carbon cap matters mainly in the second case; a plausible reason is that the cap reduces the thermal output, and with it the online thermal capacity that can hold reserve.

The adequacy margin is thus what makes reserve cheap: the firm capacity that it procures, batteries and DR in particular, can also hold reserve, so no capacity has to be built for reserve alone. In a system like the one studied here, where adequacy is procured separately, flexibility is valued mainly through energy timing and adequacy, and the explicit reserve requirement matters only at two to three times the base level. Where adequacy is not procured separately, reserve scarcity becomes a material part of the value of storage and DR.

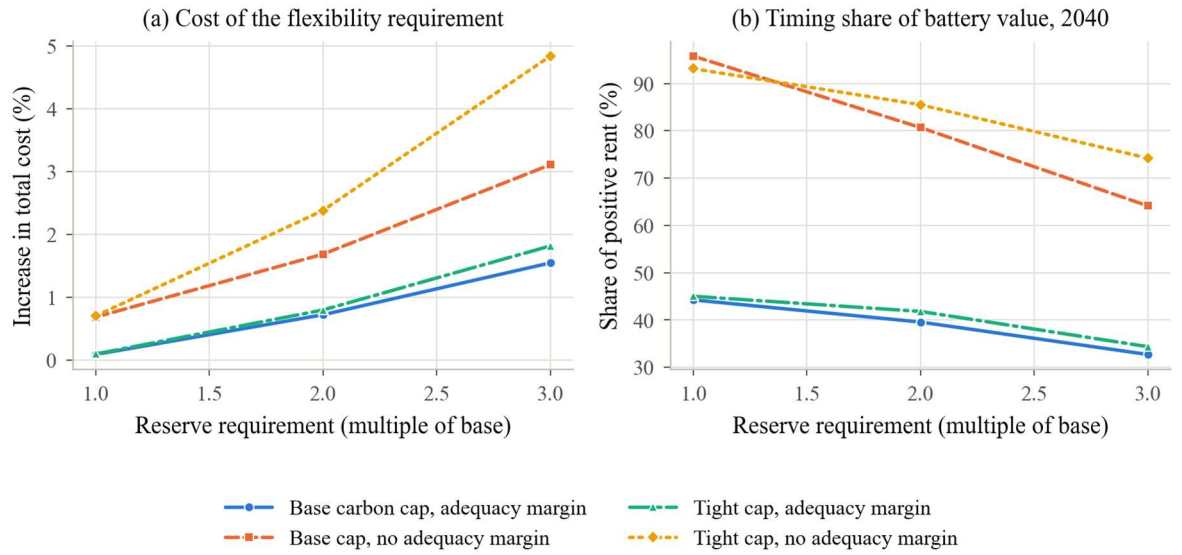

Figure 3. Value of the flexibility balance: (a) increase in the total cost relative to the energy-only plan with the same carbon cap and adequacy setting; (b) timing share of the positive rent of the 2040 battery fleet

5. DISCUSSION

This section discusses the scope of the decomposition and the main simplifications of the model and the data.

5.1. Scope of the Decomposition

The zero-profit identity of Proposition 1 holds for any linear planning model, so the decomposition applies unchanged to larger zonal models, whose zones may be obtained by partitioning the network graph [32]. It explains the plan of a planner who minimizes system cost with perfect foresight. Market revenues would differ where the market does not price one of the constraints: an energy-only market without a capacity mechanism must recover the adequacy component through scarcity prices, which our case without the adequacy constraint illustrates. The decomposition explains a plan but does not choose among plans: the scenario map trades cost against carbon and adequacy, and a choice among such alternatives by several stakeholders is a multi-attribute decision, for which methods that account for expert consensus and Pareto-optimal alternatives exist [33].

5.2. Nonconvex Costs

The identity requires convexity. With convex separable costs, e.g., rising costs of the best sites, rents equal marginal rather than average costs and the decomposition still holds at the margin; such quadratic programs can be solved efficiently [34]. Economies of scale and indivisible projects break it: they lead to indefinite separable quadratic knapsack problems [35] and to mixed-binary programs with linear constraints [36, 37], which can be solved globally but whose duals no longer recover the investment costs.

5.3. Operational Detail

Thermal fleets are clustered with continuous commitment variables, which underestimates the cost of minimum up and down times and of indivisible start-ups. Integer clustered commitment would restore indivisibility; aggregated formulations handle the identical units of a cluster without symmetry [38] and with tight relaxations [39], also for pumped-hydro plants whose units share a reservoir [40],

but the zero-profit identity would then hold only for the continuous relaxation. Reserves are required province-wide and ignore transmission limits between zones, and the requirement is a linear function of load and available VRE rather than a probabilistic sizing. Both simplifications make reserve easier to provide than in reality, so the reserve values reported here are more likely to be underestimated than overestimated.

5.4. Uncertainty

The plan is deterministic. Forecast errors enter only through the reserve requirement, and interannual variability of wind and PV is not represented. A stochastic or robust version would change the level of the adequacy and flexibility values, not the structure of the decomposition. Distributionally robust chance constraints, used for example when a virtual power plant with dispatchable hydropower offers energy and reserve under wind uncertainty [41], are one option that keeps the model convex and a dual decomposition available.

5.5. New Loads

Adequacy pays the full cost of OCGTs and about half of the storage rent in the base case, so any resource that lowers the firm peak competes for this rent. Large new loads that accept an interruption risk, such as data centres, and new electricity uses such as green-ammonia production in agricultural parks [42] change the load that adequacy must cover; neither is represented here.

5.6. Representative Days

The plan depends on the selection of representative days more than on the reserve rules (Section 4.4), and the error of the selection is not monotonic in the number of days. The full-year re-evaluation exposes this error for every plan, and the rent shares were stable across the selections we tried; representations that keep the chronology between representative days [26, 27], together with a more careful choice of extreme days, would reduce it.

5.7. Stylized Data

Costs, profiles and the fleet are illustrative. The conclusions concern mechanisms (which constraint pays for which resource and how this changes along the pathway) rather than the specific numbers of any province.

6. CONCLUSION

This paper decomposed the value of investments in a multi-stage provincial capacity-expansion model into energy volume, energy timing, reserve, adequacy, carbon and cost components, using the dual variables of the planning LP and the zero-profit condition, which makes the components add up to the investment cost of every expanded fleet. For the stylized three-zone province, four conclusions follow.

(1) Adequacy and the timing of energy, not reserve, pay for flexible resources. Adequacy pays the full cost of open-cycle gas turbines and about half of the rent of storage. The timing of energy pays most of the remainder, and its share grows as wind and PV expand: from 20% to 50% of the pumped-hydro rent between 2030 and 2040. Reserve pays 0.5% of the 2040 battery rent.

(2) The variability of wind and PV is priced as a timing discount on their energy, 13% and 22% of their energy value in 2040, which is the revenue that storage collects; the reserve requirement charged to them is below 1 $/kW-yr.

(3) The flexibility requirement adds 0.09% to the total cost when adequacy is procured with a planning margin, and the energy-only plan passes a full-year chronological check without reserve shortfall. Without the margin, the requirement costs 0.7%, reserve prices rise three- to sevenfold, and the plan sheds load in the full-year check. At three times the base requirement, reserve pays 16–36% of the battery rent.

(4) Heat-constrained coal units and the choice of representative days change the plan more than the reserve rules: the heat constraint adds 3.1 GW of batteries, and the representative days change the 2040 PV capacity by up to 8.8 GW, although the rent shares remain the same.

For planners, the decomposition answers a question that a plan alone does not: whether a resource is built for energy, for flexibility or for adequacy, and therefore which market product or requirement must remunerate it. Extensions to stochastic planning with interannual weather variability, to zonal reserve requirements with transmission limits, and to the design of capacity and reserve products are left for future work.

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