Designing Tax and Subsidy Incentives Towards a Green and Reliable Electricity Market

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Abstract

Incentive schemes and policies play an important role in reducing carbon emissions from electricity generation. This paper investigates designing tax and subsidy incentives towards a reliable and low emission electricity market, using Australia's National Electricity Market (NEM) as a case study. We propose a game-theoretical Cournot-based electricity market expansion model with tax and subsidy incentives on emission and fast response dispatchable capacity and solve it as a centralized optimization problem. Our model simultaneously decides on capacity expansion/retirement and operation of generation, storage, and transmission players, and designs long-term tax and subsidy incentives required to achieve desired levels of emission reduction and fast response generation in the network. The simulation results for Australia's NEM during 2017-2052, indicate how large investment on solar thermal technology, battery storage, and transmission lines supports high levels of Variable Renewable Energy, wind and solar, penetration in a green and reliable electricity market. Improvement of new technologies and their cost reduction trajectory show that NEM does not need any emission incentive policy for up to 45% emission intensity reduction by 2052. However, higher emission reduction targets require imposing taxes on pollutant generators and subsidizing clean generators.

Index Terms

Electricity market expansion model, Market power, Emission and fast response capacity incentive policies.

NOMENCLATURE

Indices

m	Intermittent generation firm.
n	Dispatchable generation firm.
b	Storage firm.
i, j	State (region).

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y	Investment period.
t	load time.

Parameters

α_{iyt}	Intercept of the inverse demand function.
β_{iyt}	Slope of the inverse demand function.
$EI_{Y_0}^{\mathrm{CO_2}}$	$\mathrm{CO_2}$ Emission intensity at base year Y_0.
EF_{ni}	Emission factor of the dispatchable generator.
α_y^{ER}	Emission intensity reduction coefficient.
$\alpha_{ni}^{\mathrm{dg,FR}}$	Binary coefficient to distinguish fast response dispatchable generators.
$\alpha_{bi}^{\mathrm{st,FR}}$	Binary coefficient to distinguish fast response storage firms.
α^{FR}	Fast response proportion coefficient.
$Q_{y''}^{\mathrm{old}}$	Old capacity of any generation, storage and transmission technology installed at y''.
$\bar{Q}_{mi}^{\mathrm{ig}}$	Maximum potential capacity of the intermittent generator.
c_{mi}^{ig}	Unit operation cost of the intermittent generator.
c_{ni}^{dg}	Unit operation and fuel cost of the dispatchable generator.
$\gamma_{mi}^{\mathrm{ig}}$	Binary parameter to distinguish if the intermittent generator is strategic/regulated.
$\gamma_{ni}^{\mathrm{dg}}$	Binary parameter to distinguish if the dispatchable generator is strategic/regulated.
$\gamma_{bi}^{\mathrm{st}}$	Binary parameter to distinguish if the storage firm is strategic/regulated.
$\gamma_{ij}^{\mathrm{tr}}$	Binary parameter to distinguish if the transmission line is strategic/regulated.
R_{ni}^{up},R_{ni}^{dn}	Ramping up and down coefficients of the dispatchable generator.
A_{mit}^{ig}	Energy availability coefficient of the intermittent generator.
A_{ni}^{dg}	Availability coefficient of the dispatchable generator.
A_{bi}^{st}	Availability coefficient of the storage.
A_{ij}^{tr}	Availability coefficient of the transmission line.
RA_{niy}^{dg}	Energy availability limit of the dispatchable generator during period y.
η_{bi}^{ch},η_{bi}^{dis}	Charge and discharge efficiencies of the storage.
η_{ij}^{tr}	Efficiency of the transmission line.
Inv_{miy}^{ig}	Unit investment cost of the intermittent generator.
Inv_{niy}^{dg}	Unit investment cost of the dispatchable generator.
$Inv_{biy}^{\mathrm{st^f}}$	Unit investment cost of the storage on flow capacity.
$Inv_{biy}^{\mathrm{st^v}}$	Unit investment cost of the storage on volume capacity.
Inv_{ijy}^{tr}	Unit investment cost of the transmission line.
r	Discount rate.

Variables

D_{iyt}	Electricity demand.
q_{miyt}^{ig}	Generation of the intermittent generator.
q_{niyt}^{dg}	Generation of the dispatchable generator.
q_{biyt}^{st}	Electricity flow of the storage.
q_{biyt}^{ch}	Charge of the storage.
q_{biyt}^{dis}	Discharge of the storage.
q_{ijyt}^{tr}	Electricity flow from region j to region i.
$Q_{miy}^{\mathrm{ig,new}}$	New capacity of the intermittent generator.
$Q_{niy}^{\mathrm{dg,new}}$	New capacity of the dispatchable generator.
$Q_{biy}^{\mathrm{st^f,new}}$	New flow capacity of the storage.
$Q_{biy}^{\mathrm{st^v,new}}$	New volume capacity of the storage.
$Q_{ijy}^{\mathrm{tr,new}}$	New capacity of the transmission line.

Functions

$P_{iyt}\,(.)$	Wholesale price.
$Q_{miy}^{\mathrm{ig}}(.)$	Total capacity of the intermittent generator.
$Q_{niy}^{\mathrm{dg}}(.)$	Total capacity of the dispatchable generator.
$Q_{biy}^{\mathrm{st^f}}(.)$	Total flow capacity of the storage.
$Q_{biy}^{\mathrm{st^v}}(.)$	Total volume capacity of the storage.
$Q_{ijy}^{\mathrm{tr}}(.)$	Total capacity of the transmission line.
$TS_{miyt}^{\mathrm{ig}}(.)$	Incentive (tax and subsidy) term of the intermittent generator.
$TS_{niyt}^{\mathrm{dg}}(.)$	Incentive (tax and subsidy) term of the dispatchable generator.
$TS_{biyt}^{\mathrm{st}}(.)$	Incentive (subsidy) term of the storage firm.
$C_{y}^{\mathrm{ER,ig}}(.)$	Subsidy on emission intensity reduction for the intermittent generator.
$C_{iy}^{\mathrm{FR,ig}}(.)$	Tax on intemittent electricity generation for the intermittent generator.
$C_{y}^{\mathrm{ER,dg}}(.)$	Tax or subsidy on emission intensity for the dispatchable generator.
$C_{iy}^{\mathrm{FR,dg}}(.)$	Subsidy on fast response electricity provision for the dispatchable generator.
$C_{iy}^{\mathrm{FR,st}}(.)$	Subsidy on fast response electricity provision for the storage firm.

I. Introduction

A. The Impotance of Incentive Policies in Electricity Sector

GREENHOUSE gas reduction from power generation has been firmly on the political agenda recently, following the international commitments under the Kyoto (1997) and Paris (2015) Agreements [1]. The policies imposing an emission target level in the electricity sector affect many existing fossil-fueled power plants as well as the future generation mix. For example, the U.S. Clean Power Plan incentivizes non-emitting electricity generation through the creation of a carbon price (Cap and Trade carbon policy) [2], and the US Renewable Portfolio

Standards (RPS) require that load serving entities meet a minimum portion of their load with renewable electricity [3]. Although the decline in technology cost enables renewables to compete with fossil-fueled plants in electricity generation, the incentive policies can be used to accelerate the ongoing transition toward a green network.

The emission reduction policies may lead to massive investment in renewable generation. High penetration of Variable Renewable Energy (VRE) in an electricity network can pose challenges to system reliability. Additional fast response dispatchable capacity must be introduced to the system to complement an increasing proportion of VRE generators such as wind and solar photovoltaic [4]. This may lead to new obligations in the network to ensure that the system reliability is maintained. For example, support payments are given in Germany to flexible plants to back up wind and solar, the cost of which is passed on to the final consumers via their electricity bills [5].

This paper designs long-term incentives on emission and fast response capacity for players in a competitive electricity market. We first develop a game-theoretical Cournot-based electricity market expansion model, considering the incentives as excess revenue or cost for the market players. Then, we develop a centralized optimization problem with emission and fast response dispatchable capacity constraints, the solution of which coincides with the Nash Equilibrium of our game model. The dual variable of the emission constraint at the NE is used to design the emission incentive policies and the dual variable of the fast response dispatchable capacity constraint at the NE is used to design the fast response capacity incentive policies. We implement our model to analyze Australia's five-region NEM market as the case study.

B. Related Works

The problem of electricity market expansion for studying the future generation mix or the CO_2 emission abatement has been studied in [6]–[13], with least cost generation expansion planning models, and in [14]–[21], with imperfectly competitive market expansion models. However, the electricity market expansion problem with emission and fast response dispatchable capacity incentive policies has not been investigated in the literature.

A least cost electricity generation expansion planning model, in which the total technology and operation costs to meet a specified demand are minimized, is studied in [6] considering the demand side management, and in [7] considering the simultaneous expansion of the electricity and gas networks. Multi-period power generation expansion models considering the CO_2 emission target constraint are developed in [8], [9], which calculate the additional costs of achieving a CO_2 abatement target as the absolute and marginal costs of abatement. Instead of embedding an emission target constraint, the cost of CO_2 emission is added to the fuel cost as carbon tax to support more renewable power installation in [10].

Considering a target penetration level for renewables and an ensured payback period constraints, the incentive rate (subsidy) on new renewable technologies are calculated in [11]. Incentive policies for renewable energies and emission reduction are also calculated using bilevel optimization models. Minimizing the total technology installation and operation costs in the lower level problem in [12] (or maximizing the social welfare in the lower level problem in [13]), the total policy intervention is minimized in the upper level problem to calculate the incentive policies of renewable subsidization or carbon taxation.

In order to investigate the strategic (price making) behavior of market participants, game-theoretical Cournot-based (oligopolistic) generation expansion models are developed, for instance in [14], and are compared with least cost generation expansion models in [15]. Stochastic strategic generation expansion models are developed to include the uncertainty in conjectured-price response in [16] and the uncertainty in renewable power availability in [17]. Moreover, strategic generation expansion models have been utilized to manage the CO_2 emission level in the market, with an exogenous emission permit price in [18], and with a target emission constraint in [19], [20]. It is discussed in [20] that the dual variable of the emission target constraint can be interpreted as the carbon price in the market.

The electricity market expansion models are also required to ensure that there is enough dispatchable capacity connected to the network. In order to support more investment on dispatchable capacity, the total generation from wind and solar is limited to 30% of aggregated annual generation in each region in [9], and to incentivize the right level of dispatchable capacity investment, capacity market is designed beside the energy market in [21]. The *Blueprint for the Future* report [22] suggests to limit the total VRE generation to a proportion of dispatchable generation in Australia in order to ensure the system reliability and the minimum required dispatchable capacity in the network.

C. Contributions

This paper proposes a game-theoretical Cournot-based electricity market expansion model and solves it as a centralized optimization problem. Matching the NE solution of our game model with the solution of the optimization problem, we can design the long-term incentives on emission and fast response dispatchable capacity considered in the game model based on the dual variables of the emission and fast response capacity constraints in the optimization problem. The main contributions of this paper can be summarized as:

1) A quadratic game-theoretical multi-region multi-period Cournot-based electricity market expansion model is proposed, which simultaneously solves a unified operation and installation/retirement problem and designs tax and subsidy incentives, to find the future capacity mix of strategic and regulated generation, storage and transmission players in the market.
2) The game model is solved as a centralized optimization problem. The dual variables of emission and fast response constraints at the solution of the centralized optimization problem are used to design the emission and fast response capacity incentives required to achieve desired levels of emission reduction and fast response generation support in the game model.
3) Using the dual variable of the emission intensity reduction constraint at the solution of the centralized optimization problem, we calculate the emission tax and subsidy (incentives) that generators are required to pay and receive for a targeted low emission market.

4) Using the dual variable of the fast response generation constraint at the solution of the centralized optimization problem, we calculate the fast response capacity tax and subsidy that generators and storage firms are required to either pay, because of their intermittent electricity generation, or receive, because of their fast response dispatchable electricity generation, in order to maintain the system reliable.

Under the proposed framework, an electricity generation mix for Australia's NEM is designed such that the emission intensity target is achieved and a desired level of fast response dispatchable generation proportional to the total intermittent electricity generation exists in the market.

The rest of the paper is organized as follows. The strategically competitive electricity market expansion model is formulated in Section II. The conversion of the game model to a centralized optimization problem and the solution method are presented in Section III. The simulation results are presented in Section IV. The conclusion remarks are discussed in Section V.

II. Strategically Competitive Electricity Market Expansion Model

In this section, we develop an electricity market expansion model which consists of generation, storage and transmission firms trading electricity in a multi-region energy-only wholesale electricity market. Let $\mathcal{N}_i^{\mathrm{ig}}$ be the set of intermittent generators, such as wind/PV farms and roof-top PVs, located in region i, $\mathcal{N}_i^{\mathrm{dg}}$ be the set of dispatchable generators, such as coal, gas, hydro and solar thermal power plants, located in region i, $\mathcal{N}_i^{\mathrm{st}}$ be the set of storage firms, such as pump-hydros and batteries (cooperatively controlled or non-cooperative), located in region i, and $\mathcal{N}_i^{\mathrm{tr}}$ be the set of transmission lines connected to region i.

The market expansion problem is formulated as a Cournot-based game among the generation, storage and transmission players, which are introduced in detail in Section II-C. At the NE solution of the game, the capacity investment strategies of the firms, their bidding strategies as well as the equilibrium nodal prices are calculated. We intend to design the incentives on emission and fast response capacity in the market in such a way that the constraints on emission reduction and fast response capacity are satisfied.

A. The Emission and Fast Response Capacity Constraints

We intend to design the tax and subsidy incentives on emission to limit the level of emission intensity in the market. We consider an upper bound on the emission intensity in the market as:

$$\frac{\sum\limits_{i,t} \sum\limits_{n \in \mathcal{N}_i^{\mathrm{dg}}} q_{niyt}^{\mathrm{dg}} EF_{ni}}{\sum\limits_{i,t} \sum\limits_{n \in \mathcal{N}_i^{\mathrm{dg}}} q_{niyt}^{\mathrm{dg}} + \sum\limits_{m \in \mathcal{N}_i^{\mathrm{ig}}} q_{miyt}^{\mathrm{ig}}} \leq \left(1 - \alpha_y^{\mathrm{ER}}\right) EI_{Y_0}^{\mathrm{CO_2}} : \mu_y^{\mathrm{ER}} \ \forall y \tag{1}$$

where $EI_{Y_0}^{\mathrm{CO_2}}$ is the $\mathrm{CO_2}$ emission intensity of the whole electricity sector at base (reference) year Y_0, α_y^{ER} is the desired percentage of emission intensity reduction at period y relative to the base period Y_0, q_{miyt}^{ig} is the electricity generation of intermittent generator m in region i , q_{niyt}^{dg} is the electricity generation of dispatchable generator n

in region i, and EF_{ni} is the emission factor of fossil-fueled dispatchable generator n in region i. The dual variable associated with this constraint, i.e., μ_y^{ER}, is used to design the emission tax/subsidy (first incentive policy) to achieve a level of emission intensity, as shown in Section III-C.

We also intend to design tax and subsidy incentives on fast response dispatchable capacity to support installation of fast response generation capacity in the market. We limit the total VRE generation to a proportion of fast response generation during each investment period to ensure adequacy of fast response capacity in the network as:

$$\sum_t \left(\sum_{n \in \mathcal{N}_i^{\mathrm{dg}}} \alpha_{ni}^{\mathrm{dg,FR}} q_{niyt}^{\mathrm{dg}} + \sum_{b \in \mathcal{N}_i^{\mathrm{st}}} \alpha_{bi}^{\mathrm{st,FR}} q_{biyt}^{\mathrm{dis}} \right) \geq \alpha^{\mathrm{FR}} \sum_t \sum_{m \in \mathcal{N}_i^{\mathrm{ig}}} q_{miyt}^{\mathrm{ig}} \ : \ \mu_{iy}^{\mathrm{FR}} \quad \forall i, y \tag{2}$$

where α^{FR} is the fast response proportion coefficient, $\alpha_{ni}^{\mathrm{dg,FR}}$ is a binary coefficient which is one if firm n in region i is a fast response dispatchable generator, such as gas-fired or hydro, $\alpha_{bi}^{\mathrm{st,FR}}$ is a binary coefficient which is one if firm b in region i is a pump-hydro or a cooperatively controlled battery, and q_{biyt}^{dis} is the electricity discharge level of the storage firm b in region i. It is also shown in Section III-C that the required capacity subsidy/tax to ensure enough fast response capacity exists in the network is calculated based on the dual variable of the fast response constraint, μ_{iy}^{FR}.

Note that we can reduce the coefficient α^{FR}, i.e., the need for fast response capacity to achieve diversity dividends, by spreading the wind and solar generation across the network, which smooths the generation and ramping up and down of the total regional intermittent electricity generation [23].

B. Total Capacity and Investment Functions

In our model, any player can retrofit its capacity at any investment period y. The total capacity of each firm at period y, Q_y, is the sum of incumbent (old) capacities, Q_y^{old}, which are given as exogenous input to the model, and new capacities, Q_y^{new}, which are decision variables of players, as:

$$Q_y(Q_{y' \leq y}^{\mathrm{new}}) = \sum_{y'=\max(1, y-PL+1)}^{y} Q_{y'}^{\mathrm{new}} + \sum_{y''=\mathrm{Y}_0-PL+y+1}^{\mathrm{Y}_0} Q_{y''}^{\mathrm{old}} \tag{3}$$

where PL denotes the plant life of the corresponding technology of the firm, and Y_0 is the base year in our study. Note that firms in our model are able to decommission their capacities at any period before they reach their plant life and each technology must become retired in our model when it reaches its plant life.

Market expansion models which assume annualized investment cost for technologies do not take capacity retirement into account [16]. Instead of using the annualized investment cost, we consider the whole technology costs and deduct the end of period remaining value of new capacities [20] from their investment costs in our model as:

$$Inv_y = \left(1 - \frac{\max(0, PL + y - N_Y - 1)}{PL}\right) \tilde{Inv} \tag{4}$$

where $\tilde{Inv}$ is the actual investment cost of a unit and Inv_y is the modified value of investment cost at period y in our model. For instance, in a 25-year period simulation study, $N_Y = 25$, if a firm with the technology plant life of 20 years decides to install a new unit at year 21, it just pays $\frac{1}{4}$ of the actual investment cost in our model. Note that we include the yearly maintenance costs of technologies as part of their investment costs and do not consider them separately.

C. The Market Expansion Game

In this subsection, we introduce the market expansion game, the utility function of players and their decision variables. In our model, each firm decides on its expansion capacity and bidding strategies over the planning horizon, being either strategic or regulated. Strategic firms (price maker players) can potentially exercise market power to increase the price above the perfect competition level, but regulated firms are subject to regulations which impede them from exercising market power, i.e., are price taker.

In our model, the electricity price in region i at investment period y, with duration of five years, and load time t, with duration of one hour, is given by the following, commonly-used linear inverse demand function:

$$P_{iyt} = \alpha_{iyt} - \beta_{iyt} D_{iyt} \quad \forall i, y, t \tag{5}$$

$$D_{iyt} = \sum_{m \in \mathcal{N}_i^{\mathrm{ig}}} q_{miyt}^{\mathrm{ig}} + \sum_{n \in \mathcal{N}_i^{\mathrm{dg}}} q_{niyt}^{\mathrm{dg}} + \sum_{b \in \mathcal{N}_i^{\mathrm{st}}} q_{biyt}^{\mathrm{st}} + \sum_{j \in \mathcal{N}_i^{\mathrm{tr}}} \left(\eta_{ij}^{\mathrm{tr}} q_{ijyt}^{\mathrm{tr}} - q_{jiyt}^{\mathrm{tr}} \right) \quad \forall i, y, t \tag{6}$$

where α_{iyt} and β_{iyt} are positive real values for the inverse demand function in region i at period y, and load time t. Besides, q_{biyt}^{st} is the electricity flow from storage firm b in region i, and q_{ijyt}^{tr} is the electricity flow from region j to region i at period y, and load time t. Note that the total amount of power supply from the generation, storage and transmission firms in region i is equal to the regional net electricity demand, as shown in (6), which represents the regional (nodal) electricity balance in our work.

Although roof-top PVs and residential batteries do not participate in the wholesale market, their operation affects the market price, i.e., shifts the inverse demand function up or down. For example, when new roof-top PVs with the generation amount of ΔD_{iyt} is installed, it shifts the inverse demand function in the wholesale market down, i.e., the equation (5) changes to $P_{iyt} = \alpha_{iyt}^{'} - \beta_{iyt} D_{iyt}$, where $\alpha_{iyt}^{'} = (\alpha_{iyt} - \beta_{iyt} \Delta D_{iyt})$. Equivalently, we can consider the generation of ΔD_{iyt} in the wholesale market and write the equation (5) as $P_{iyt} = \alpha_{iyt} - \beta_{iyt} \left(\Delta D_{iyt} + D_{iyt} \right).$ Thus, instead of considering predetermined capacities of roof-top PVs and residential batteries on the demand side, we equivalently model them on the supply side as perfectly competitive players, and decide on their capacities in our model.

In what follows, the variable μ indicates the associated Lagrange multiplier or dual variable of its corresponding constraint, the price function $P_{iyt}(.)$ refers to (5) and the total capacity function $Q(.)$ refers to (3). We explain in section III-C how the tax and subsidy incentive terms, $TS(.)$, are designed to ensure the satisfaction of the emission constraint (1) and the fast response constraint (2) in our game model.

1) Intermittent Generation Firms: The mth intermittent generator, i.e., wind or solar farm or roof-top PVs, in region i maximizes its profit by solving the following optimization problem, given the tax and subsidy term $TS^{\text{ig}}_{miyt} = \left(C^{\text{ER,ig}}_{y}(.) + C^{\text{FR,ig}}_{iy}(.)\right) q^{\text{ig}}_{miyt}$:

$$\max_{\substack{\{q^{\text{ig}}_{miyt}\}_{yt}\succeq 0\\ \{Q^{\text{ig,new}}_{miy}\}_{y}\succeq 0}} \sum_{y,t} \Delta\ell \frac{P_{iyt}(.)q^{\text{ig}}_{miyt} - c^{\text{ig}}_{mi}q^{\text{ig}}_{miyt} + \gamma^{\text{ig}}_{mi}\frac{\beta_{iyt}{q^{\text{ig}}_{miyt}}^2}{2} + TS^{\text{ig}}_{miyt}(.)}{(1+r)^y} - \sum_{y} \frac{Inv^{\text{ig}}_{miy}Q^{\text{ig,new}}_{miy}}{(1+r)^y} \tag{7a}$$

s.t.

$$q^{\text{ig}}_{miyt} \leq A^{ig}_{mit}Q^{\text{ig}}_{miy}(.) \;:\; \mu^{\text{ig}}_{miyt} \quad \forall y,t \tag{7b}$$

$$Q^{\text{ig}}_{miy}(.) \leq \bar{C}^{\text{ig}}_{mi} \;:\; \mu^{\text{ig},\bar{\text{Q}}}_{miy} \quad \forall y,t \tag{7c}$$

where $\Delta\ell$ is the length of each time load during each investment period, $Q^{\text{ig,new}}_{miy}$ and $Q^{\text{ig}}_{miy}(.)$ are the new capacity (variable) and the total generation capacity (function) of the intermittent (VRE) firm m in region i at period y, respectively. The first term in the summation in (7a) is the net present value of electricity generation revenue, the second term represents the generation cost with unit cost of c^{ig}_{mi}, the third term denotes the regulation surplus when γ^{ig}_{mi} is one, and the fourth term represents the tax and subsidy, given the discount rate r over the periods $y \in \{1, ..., N_Y\}$. The last term in (7a) is the total investment cost of new capacities, with unitary investment cost of Inv^{ig}_{miy}, over the periods. Depending on the binary parameter γ^{ig}_{mi}, the mth intermittent generation firm in region i behaves strategically or in a regulated manner. The firm acts strategically when γ^{ig}_{mi} is zero or acts as a regulated firm when γ^{ig}_{mi} is one. Considering the market efficiency term, $\frac{\beta_{iyt}{q^{\text{ig}}_{miyt}}^2}{2}$, in the objective function, the firm becomes regulated (price-taker). The tax and subsidy term TS^{ig}_{miyt} represents the revenue due to emission reduction subsidy $C^{\text{ER,ig}}_{y}(.)$, and the cost due to intermittent electricity generation tax $C^{\text{FR,ig}}_{y}(.)$. The constraint (7b) considers the regional intermittent energy availability coefficient in load time t, A^{ig}_{mit}, and the constraint (7c) limits the electricity generation to the maximum potential capacity, $\bar{Q}^{\text{ig}}_{mi}$, e.g., the roof-top PV installation area limit.

2) Dispatchable Generation Firms: The strategy of the nth dispatchable generator, i.e., coal, gas, biomass, hydro or solar thermal firms, in region i is obtained by solving the following optimization problem, given the tax and subsidy term $TS^{\text{dg}}_{niyt} = \left(C^{\text{ER,dg}}_{y}(.) + C^{\text{FR,dg}}_{iy}(.)\right) q^{\text{dg}}_{niyt}$:

$$\max_{\substack{\{q^{\text{dg}}_{niyt}\}_{yt}\succeq 0\\ \{Q^{\text{dg,new}}_{niy}\}_{y}\succeq 0}} \sum_{y,t} \Delta\ell \frac{\left(P_{iyt}(.) - c^{\text{dg}}_{ni}\right) q^{\text{dg}}_{niyt} + \gamma^{\text{dg}}_{ni}\frac{\beta_{iyt}{q^{\text{dg}}_{niyt}}^2}{2} + TS^{\text{dg}}_{niyt}(.)}{(1+r)^y} - \sum_{y} \frac{Inv^{\text{dg}}_{niy}Q^{\text{dg,new}}_{niy}}{(1+r)^y} \tag{8a}$$

s.t.

$$q_{niyt}^{\mathrm{dg}} \leq A_{ni}^{\mathrm{dg}} Q_{niy}^{\mathrm{dg}}(.) \ : \ \mu_{niyt}^{\mathrm{dg}} \quad \forall y,t \tag{8b}$$

$$q_{niyt}^{\mathrm{dg}} - q_{niy(t-1)}^{\mathrm{dg}} \leq R_{ni}^{\mathrm{up}} A_{ni}^{\mathrm{dg}} Q_{niy}^{\mathrm{dg}}(.) \ : \ \mu_{niyt}^{\mathrm{dg,up}} \ \forall y,t \tag{8c}$$

$$q_{niy(t-1)}^{\mathrm{dg}} - q_{niyt}^{\mathrm{dg}} \leq R_{ni}^{\mathrm{dn}} A_{ni}^{\mathrm{dg}} Q_{niy}^{\mathrm{dg}}(.) \ : \ \mu_{niyt}^{\mathrm{dg,dn}} \ \forall y,t \tag{8d}$$

$$\sum_{t} q_{niyt}^{\mathrm{dg}} \leq RA_{niy}^{\mathrm{dg}} \ : \ \mu_{niy}^{\mathrm{dg,RA}} \ \forall n,i,y \tag{8e}$$

where $Q_{niy}^{\mathrm{dg,new}}$ and $Q_{niy}^{\mathrm{dg}}(.)$ are the new capacity (variable) and total generation capacity (function) of the dispatchable firm n in region i at period y. The parameter c_{ni}^{dg} represents the firm's marginal operation and fuel cost of electricity generation and the parameter Inv_{niy}^{dg} is its unitary investment cost. Depending on the binary parameter $\gamma_{ni}^{\mathrm{dg}}$, the nth dispatchable generator in region i acts strategically when $\gamma_{ni}^{\mathrm{dg}}$ is zero or acts as a regulated firm when $\gamma_{ni}^{\mathrm{dg}}$ is one, given the market efficiency term $\frac{\beta_{iyt} {q_{niyt}^{\mathrm{dg}}}^2}{2}$. Depending on its emission intensity factor, the firm may pay or receive the emission incentive $C_{y}^{\mathrm{ER,dg}}(.)$. The firm receives the subsidy $C_{y}^{\mathrm{FR,dg}}(.)$ if it is able to provide fast response generation, given the tax and subsidy term TS_{niyt}^{dg}. The constraint (8b) limits the electricity generation to its energy flow capacity with availability coefficient A_{ni}^{dg}. Constraints (8c) and (8d) ensure that the nth dispatchable generator meets its ramping limits, with ramping up and down coefficients R_{ni}^{up} and R_{ni}^{dn}, and constraint (8e) limits the electricity generation during period y to energy availability limit RA_{niy}^{dg}, e.g. the dam water availability limit for hydros.

3) Storage Firms: The strategy of the bth storage firm, i.e., pump-hydro, or cooperatively controlled or non-cooperative batteries (cooperative batteries are able to provide fast response generation in the network), in region i is obtained by solving the following optimization problem, given the tax and subsidy term $TS_{biyt}^{\mathrm{st}} = C_{iy}^{\mathrm{FR,st}}(.) q_{biyt}^{\mathrm{dis}}$:

$$\max_{\substack{\left\{q_{biyt}^{\mathrm{dis}}, q_{biyt}^{\mathrm{ch}}\right\}_{yt} \succeq 0 \\ \left\{Q_{biy}^{\mathrm{st^f,new}}, Q_{biy}^{\mathrm{st^v,new}}\right\}_{y} \succeq 0 \\ \left\{q_{biyt}^{\mathrm{st}}\right\}_{yt}}} \sum_{y,t} \Delta\ell \frac{P_{iyt}(.)\, q_{biyt}^{\mathrm{st}} + \gamma_{bi}^{\mathrm{st}} \frac{\beta_{iyt} {q_{biyt}^{\mathrm{st}}}^2}{2} + TS_{biyt}^{\mathrm{st}}(.)}{(1+r)^y} - \sum_{y} \frac{Inv_{biy}^{\mathrm{st^v}} Q_{biy}^{\mathrm{st^v,new}} + Inv_{biy}^{\mathrm{st^f}} Q_{biy}^{\mathrm{st^f,new}}}{(1+r)^y} \tag{9a}$$

s.t.

$$q_{biyt}^{\mathrm{st}} = \eta_{bi}^{\mathrm{dis}} q_{biyt}^{\mathrm{dis}} - \frac{q_{biyt}^{\mathrm{ch}}}{\eta_{bi}^{\mathrm{ch}}} \ : \ \mu_{biyt}^{\mathrm{st}} \quad \forall y,t \tag{9b}$$

$$q_{biyt}^{\mathrm{dis}} \leq A_{bi}^{\mathrm{st}} Q_{biy}^{\mathrm{st^f}}(.) \ : \ \mu_{biyt}^{\mathrm{dis}} \quad \forall y,t \tag{9c}$$

$$q_{biyt}^{\mathrm{ch}} \leq A_{bi}^{\mathrm{st}} Q_{biy}^{\mathrm{st^f}}(.) \ : \ \mu_{biyt}^{\mathrm{ch}} \quad \forall y,t \tag{9d}$$

$$0 \leq \sum_{t'=1}^{t} \left(q_{biyt'}^{\mathrm{ch}} - q_{biyt'}^{\mathrm{dis}}\right) \Delta \leq A_{bi}^{\mathrm{st}} Q_{biy}^{\mathrm{st^v}}(.) \ : \ \mu_{biyt}^{\mathrm{st,min}}, \mu_{biyt}^{\mathrm{st,max}} \ \forall y,t \tag{9e}$$

$$q_{biyt}^{\mathrm{dis}} q_{biyt}^{\mathrm{ch}} = 0 \ : \ \mu_{biyt}^{\mathrm{dis/ch}} \quad \forall y,t \tag{9f}$$

where $Q_{biy}^{\mathrm{st^v,new}}$ and $Q_{biy}^{\mathrm{st^f,new}}$ are the new volume and flow capacity (variable), and $Q_{biy}^{\mathrm{st^v}}(.)$ and $Q_{biy}^{\mathrm{st^f}}(.)$ are the total volume and flow capacity (function) of the storage firm b in region i at period y, respectively. Note that the unit for volume capacity is MWh (energy) and for flow capacity is MW (power). The parameters $Inv^{\mathrm{st^v}}_{biy}$ and $Inv^{\mathrm{st^f}}_{biy}$ are the firm's unitary volume and flow investment costs, respectively. The firm receives the subsidy $C^{\mathrm{FR,st}}_{y}(.)$ if it is able to provide fast response generation service, given the tax and subsidy term TS^{st}_{biyt}. Depending on the binary parameter $\gamma^{\mathrm{st}}_{bi}$, the bth storage firm in region i acts strategically when $\gamma^{\mathrm{st}}_{bi}$ is zero and acts as a regulated firm when $\gamma^{\mathrm{st}}_{bi}$ is one, given the market efficiency term $\frac{\beta_{iyt}{q^{\mathrm{st}}_{biyt}}^2}{2}$. The equality (9b) defines the net output/input flow of electricity, q^{st}_{biyt}, from/to storage firm b in region i. The constraints (9c) and (9d) limit the energy flow (discharge q^{dis}_{biyt} and charge q^{ch}_{biyt}) of the firm to its flow (discharge/charge) capacity with availability factor A^{st}_{bi}. Constraint (9e) ensures the volume capacity limit of the storage firm is always met. Finally, constraint (9f) prevents the storage firm charge and discharge simultaneously, which is the only non-linear constraint in our model. Note that as the storage firm receives the subsidy $C^{\mathrm{FR,st}}_{iy}(.)$ while discharging, the model may decide to simultaneously charge and discharge to maximize its objective function. Therefore, we need the constraint (9f) to prevent simultaneous charge and discharge of the storage firm.

4) Transmission Firms: The strategy of the transmission line between regions i and j, which buys and sells electricity in regions it connects, is obtained by solving the following optimization problem:

$$\max_{\substack{\{q^{\mathrm{tr}}_{jiyt}, q^{\mathrm{tr}}_{ijyt}\}_{yt}\succeq 0\\ \{Q^{\mathrm{tr,new}}_{ijy}, Q^{\mathrm{tr,new}}_{jiy}\}_{y}\succeq 0}} \sum_{y,t} \Delta\ell \frac{\left(\eta^{\mathrm{tr}}_{ij}P_{jyt}(.) - P_{iyt}(.)\right) q^{\mathrm{tr}}_{jiyt} + \left(\eta^{\mathrm{tr}}_{ij}P_{iyt}(.) - P_{jyt}(.)\right) q^{\mathrm{tr}}_{ijyt} + \gamma^{\mathrm{tr}}_{ij}\left(\left({\eta^{\mathrm{tr}}_{ij}}^2\beta_{iyt} + \beta_{jyt}\right)\frac{{q^{\mathrm{tr}}_{ijyt}}^2}{2} + \left({\eta^{\mathrm{tr}}_{ij}}^2\beta_{jyt} + \beta_{iyt}\right)\frac{{q^{\mathrm{tr}}_{jiyt}}^2}{2} - \eta^{\mathrm{tr}}_{ij}\left(\beta_{jyt} + \beta_{iyt}\right) q^{\mathrm{tr}}_{ijyt} q^{\mathrm{tr}}_{jiyt} \right)}{(1+r)^y} - \sum_{y} \frac{\frac{Inv^{\mathrm{tr}}_{ijy}}{2}\left(Q^{\mathrm{tr,new}}_{ijy} + Q^{\mathrm{tr,new}}_{jiy}\right)}{(1+r)^y} \tag{10a}$$

s.t.

$$q^{\mathrm{tr}}_{ijyt} \le A^{\mathrm{tr}}_{ij} Q^{\mathrm{tr}}_{ijy}(.) \;:\; \mu^{\mathrm{tr}}_{ijyt} \quad \forall y,t \tag{10b}$$

$$Q^{\mathrm{tr,new}}_{ijy} = Q^{\mathrm{tr,new}}_{jiy} \;:\; \mu^{\mathrm{tr,Q}}_{ijy} \quad \forall y \tag{10c}$$

where $Q^{\mathrm{tr,new}}_{ijy}$ and $Q^{\mathrm{tr}}_{ijy}(.)$ are the new capacity (variable) and the total transmission capacity (function) of the transmission firm between regions i and j at period y. The first term in summation in (10a) is the electricity profit of transmitting electricity from region i to region j, the second term is the backward profit, the third term denotes the regulation surplus and the last term is the total investment cost of new capacities, with unitary investment cost of Inv^{tr}_{ijy}. Depending on the binary parameter $\gamma^{\mathrm{tr}}_{ij}$, the transmission line between regions i and j acts strategically when $\gamma^{\mathrm{tr}}_{ij}$ is zero or acts as a regulated firm when $\gamma^{\mathrm{tr}}_{ij}$ is one, given the market efficiency term $\left({\eta^{\mathrm{tr}}_{ij}}^2\beta_{iyt} + \beta_{jyt}\right)\frac{{q^{\mathrm{tr}}_{ijyt}}^2}{2} + \left({\eta^{\mathrm{tr}}_{ij}}^2\beta_{jyt} + \beta_{iyt}\right)\frac{{q^{\mathrm{tr}}_{jiyt}}^2}{2} - \eta^{\mathrm{tr}}_{ij}\left(\beta_{jyt} + \beta_{iyt}\right) q^{\mathrm{tr}}_{ijyt} q^{\mathrm{tr}}_{jiyt}$. Note that the electricity markets with regulated transmission lines are discussed as *electricity markets with transmission constraints* in the literature, e.g., [24]–[26]. The constraint (10b), in order to consider the congestion in the transmission network, limits the electricity flow to the capacity of transmission lines with availability coefficient A_{ij}^{tr}, and the constraint (10c) ensures that transmission capacity on both directions of the line is equal in our model.

Note that the profit maximization problem (10a) looks more complex than our previous formulation in [27] because of considering the transmission efficiency, η_{ij}^{tr}, which was missing before.

III. Solution Methodology

In this section, we first provide a game-theoretic analysis of the market expansion problem between generation, storage and transmission players considering the tax and subsidy incentive policies. Next, we develop a centralized optimization problem with the constraints on emission (1) and fast response generation (2), and use its solution to design the tax and subsidy incentives in the game model. It is shown that the solution of the centralized problem coincides with the NE solution of the game model.

A. Game-theoretic Analysis of the Market Expansion Model

To solve the market expansion game, we need to study the best response functions of all firms participating in the market. Then, any intersection of all firms' best response functions will be a NE. At the NE strategy of the game, no player has any incentive to unilaterally deviate its strategy from the NE point.

Note that (9f), which is nonlinear, is the only constraint in our model that violates the sufficient conditions of Theorem 4.4 in [28] for existence of NE point. However, in our numerical results, we find the NE point of the game by varying the initial point of the optimization algorithm.

1) Best Responses of Intermittent Generation Firms: The best response of the intermittent generator m in region i, given the strategies of other firms in the market, satisfies the necessary and sufficient Karush-Kuhn-Tucker (KKT) conditions ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

$$\Delta l \frac{P_{iyt}\left(.\right) - c_{mi}^{\text{ig}} - \left(1 - \gamma_{mi}^{\text{ig}}\right) \beta_{iyt} q_{miyt}^{\text{ig}} + C_y^{\text{ER,ig}}(.) + C_{iy}^{\text{FR,ig}}(.)}{(1+r)^y} - \mu_{miyt}^{\text{ig}} \leq 0 \ \perp \ q_{miyt}^{\text{ig}} \geq 0 \tag{11a}$$

$$\frac{-Inv_{miy}^{\text{ig}}}{(1+r)^y} - \sum_{y'=y}^{\min(N_Y, y+PL_{mi}^{\text{ig}}-1)} \left(\mu_{miy'}^{\text{ig},\bar{\text{Q}}} - \sum_t A_{mit}^{\text{ig}} \mu_{miy't}^{\text{ig}} \right) \leq 0 \ \perp \ Q_{miy}^{\text{ig,new}} \geq 0 \tag{11b}$$

$$q_{miyt}^{\text{ig}} \leq A_{mit}^{\text{ig}} Q_{miy}^{\text{ig}}(.) \ \perp \ \mu_{miyt}^{\text{ig}} \geq 0 \tag{11c}$$

$$q_{miyt}^{\text{ig}} \leq \bar{Q}_{mi}^{\text{ig}} \ \perp \ \mu_{miyt}^{\text{ig},\bar{\text{Q}}} \geq 0 \tag{11d}$$

where the perpendicularity sign, $\perp$, indicates that one of the adjacent inequalities must at least be satisfied as an equality [29].

2) Best Responses of Dispatchable Generation Firms: The best response of the dispatchable generator n in region i, given the collection of strategies of other firms in the market, is obtained by solving the following KKT conditions ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

$$\Delta l \frac{P_{iyt}(.) - c^{\mathrm{dg}}_{ni} - \left(1-\gamma^{\mathrm{dg}}_{ni}\right)\beta_{iyt} q^{\mathrm{dg}}_{niyt} + C^{\mathrm{ER,ig}}_{y}(.) + C^{\mathrm{FR,ig}}_{iy}(.)}{(1+r)^y} - \mu^{\mathrm{dg}}_{niyt} + \mu^{\mathrm{up}}_{niy(t+1)} - \mu^{\mathrm{up}}_{niyt} - \mu^{\mathrm{dn}}_{niy(t+1)} + \mu^{\mathrm{dn}}_{niyt} - \mu^{\mathrm{dg,RA}}_{niy} \leq 0 \;\perp\; q^{\mathrm{dg}}_{niyt} \geq 0 \tag{12a}$$

$$\frac{-Inv^{\mathrm{dg}}_{niy}}{(1+r)^y} + \sum_t A^{\mathrm{dg}}_{ni} \sum_{y'=y}^{\min(N_Y, y+PL^{\mathrm{dg}}_{ni}-1)} \left(\mu^{\mathrm{dg}}_{niy't} + R^{\mathrm{up}}_{ni}\mu^{\mathrm{up}}_{niy't} + R^{\mathrm{dn}}_{ni}\mu^{\mathrm{dn}}_{niy't}\right) \leq 0 \;\perp\; Q^{\mathrm{dg,new}}_{niy} \geq 0 \tag{12b}$$

$$q^{\mathrm{dg}}_{niyt} \leq A^{\mathrm{dg}}_{ni} Q^{\mathrm{dg}}_{niy}(.) \;\perp\; \mu^{\mathrm{dg}}_{niyt} \geq 0 \tag{12c}$$

$$q^{\mathrm{dg}}_{niyt} - q^{\mathrm{dg}}_{niy(t-1)} \leq R^{\mathrm{up}}_{ni} A^{\mathrm{dg}}_{ni} Q^{\mathrm{dg}}_{niy}(.) \;\perp\; \mu^{\mathrm{up}}_{niyt} \geq 0 \tag{12d}$$

$$q^{\mathrm{dg}}_{niy(t-1)} - q^{\mathrm{dg}}_{niyt} \leq R^{\mathrm{dn}}_{ni} A^{\mathrm{dg}}_{ni} Q^{\mathrm{dg}}_{niy}(.) \;\perp\; \mu^{\mathrm{dn}}_{niyt} \geq 0 \tag{12e}$$

$$\sum_t q^{\mathrm{dg}}_{niyt} \leq RA^{\mathrm{dg}}_{niy} \;\perp\; \mu^{\mathrm{dg,RA}}_{niy} \geq 0 \tag{12f}$$

3) Best Responses of Storage Firms: The best response of the storage firm b in region i, given the collection of strategies of other firms in the market, is obtained by solving the following KKT conditions ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

$$\Delta l \frac{P_{iyt}(.) - \left(1-\gamma^{\mathrm{st}}_{bi}\right)\beta_{iyt} q^{\mathrm{st}}_{biyt}}{(1+r)^y} + \mu^{\mathrm{st}}_{biyt} = 0 \tag{13a}$$

$$\Delta l \frac{C^{\mathrm{FR,st}}_{y}(.)}{(1+r)^y} - \eta^{\mathrm{dis}}_{bi}\mu^{\mathrm{st}}_{biyt} - \mu^{\mathrm{dis}}_{biyt} - \Delta \sum_{t'=t}^{N_T} \mu^{\mathrm{st,min}}_{biyt'} - \mu^{\mathrm{st,max}}_{biyt'} + \mu^{\mathrm{dis/ch}}_{biyt} q^{\mathrm{ch}}_{biyt} \leq 0 \;\perp\; q^{\mathrm{dis}}_{biyt} \geq 0 \tag{13b}$$

$$\frac{\mu^{\mathrm{st}}_{biyt}}{\eta^{\mathrm{ch}}_{bi}} - \mu^{\mathrm{ch}}_{biyt} + \Delta \sum_{t'=t}^{N_T} \mu^{\mathrm{st,min}}_{biyt'} - \mu^{\mathrm{st,max}}_{biyt'} + \mu^{\mathrm{dis/ch}}_{biyt} q^{\mathrm{dis}}_{biyt} \leq 0 \;\perp\; q^{\mathrm{ch}}_{biyt} \geq 0 \tag{13c}$$

$$\frac{-Inv^{\mathrm{st^v}}_{biy}}{(1+r)^y} + \sum_t A^{\mathrm{st}}_{bi} \sum_{y'=y}^{\min(N_Y, y+PL^{\mathrm{st^v}}_{bi}-1)} \mu^{\mathrm{st,max}}_{biy't} \leq 0 \;\perp\; Q^{\mathrm{st^v,new}}_{biy} \geq 0 \tag{13d}$$

$$\frac{-Inv^{\mathrm{st^f}}_{biy}}{(1+r)^y} + \sum_t A^{\mathrm{st}}_{bi} \sum_{y'=y}^{\min(N_Y, y+PL^{\mathrm{st^f}}_{bi}-1)} \mu^{\mathrm{dis}}_{biy't} + \mu^{\mathrm{ch}}_{biy't} \leq 0 \;\perp\; Q^{\mathrm{st^f,new}}_{biy} \geq 0 \tag{13e}$$

$$q^{\mathrm{st}}_{biyt} = \eta^{\mathrm{dis}}_{bi} q^{\mathrm{dis}}_{biyt} - \frac{q^{\mathrm{ch}}_{biyt}}{\eta^{\mathrm{ch}}_{bi}} \tag{13f}$$

$$q^{\mathrm{dis}}_{biyt} \leq A^{\mathrm{st}}_{bi} Q^{\mathrm{st^f}}_{biy}(.) \;\perp\; \mu^{\mathrm{dis}}_{biyt} \geq 0 \tag{13g}$$

$$q^{\mathrm{ch}}_{biyt} \leq A^{\mathrm{st}}_{bi} Q^{\mathrm{st^f}}_{biy}(.) \;\perp\; \mu^{\mathrm{ch}}_{biyt} \geq 0 \tag{13h}$$

$$0 \leq \sum_{t'=1}^{t} \left(q^{\mathrm{ch}}_{biyt'} - q^{\mathrm{dis}}_{biyt'}\right)\Delta \;\perp\; \mu^{\mathrm{st,min}}_{biyt} \geq 0 \tag{13i}$$

$$\sum_{t'=1}^{t} \left(q^{\mathrm{ch}}_{biyt'} - q^{\mathrm{dis}}_{biyt'}\right)\Delta \leq A^{\mathrm{st}}_{bi} Q^{\mathrm{st^v}}_{biy}(.) \;\perp\; \mu^{\mathrm{st,max}}_{biyt} \geq 0 \tag{13j}$$

$$q^{\mathrm{dis}}_{biyt} q^{\mathrm{ch}}_{biyt} = 0 \tag{13k}$$

4) Best Responses of Transmission Firms: Finally, the best response of the transmission firm between regions i and j, given the collection of strategies of other firms in the market, can be obtained using the KKT conditions ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

$$\Delta l \frac{\eta_{ij}^{\text{tr}} P_{iyt}\left(.\right) - P_{jyt}\left(.\right) + \left(1 - \gamma_{ij}^{\text{tr}}\right)\left((-\beta_{iyt}{\eta_{ij}^{\text{tr}}}^2 - \beta_{jyt})q_{ijyt}^{\text{tr}} + \eta_{ij}^{\text{tr}}\left(\beta_{iyt} + \beta_{jyt}\right) q_{jiyt}^{\text{tr}}\right)}{(1+r)^y} - \mu_{ijyt}^{\text{tr}} \leq 0 \ \perp \ q_{ijyt}^{\text{tr}} \geq 0 \tag{14a}$$

$$\frac{\frac{-Inv_{ijy}^{\text{tr}}}{2}}{(1+r)^y} + \mu_{ijy}^{\text{tr,Q}} - \mu_{jiy}^{\text{tr,Q}} + \sum_t A_{ij}^{\text{tr}} \sum_{y'=y}^{\min(N_Y, y+PL_{ij}^{\text{tr}}-1)} \mu_{ijy't}^{\text{tr}} \leq 0 \perp \ Q_{ijy}^{\text{tr,new}} \geq 0 \tag{14b}$$

$$q_{ijyt}^{\text{tr}} \leq A_{ij}^{\text{tr}} Q_{ijy}^{\text{tr}}(.) \ \perp \ \mu_{ijyt}^{\text{tr}} \geq 0 \tag{14c}$$

$$Q_{ijy}^{\text{tr,new}} = Q_{jiy}^{\text{tr,new}} \tag{14d}$$

The NE solution is by definition the intersection of best responses of all players. Therefore, it satisfies the KKT conditions of all market players, that is, (11a-11d), (12a-12f), (13a-13k), and (14a-14d). Note that, our numerical results show that a unique NE point exists in the game. However, due to the non-convex constraint (9f), we cannot provide a theoretical statement on existence or uniqueness of the NE solution.

Next, we develop a centralized optimization problem with the emission and fast response capacity constraints. Matching the KKT conditions of the game with the KKT conditions of the centralized optimization problem, we design the tax and subsidy incentives in the game model. Finding the equivalent optimization problem for a game model is discussed in detail in [30] for electricity markets with strategic generation players and regulated transmission lines. But, this methodology has never been applied to design tax and subsidy in the market.

Note that there exists an equivalent centralized optimization problem for an operational or investment Cournot-based electricity market model only when the inverse demand function is linear, i.e., the model is quadratic.

B. Solving the Game as a Centralized Optimization Problem

In this section, we develop a centralized optimization problem, which embodies the individual user optimization problems of generation, storage and transmission players in II-C, as following:

$$\max_{\substack{\left\{q_{miyt}^{\text{ig}}, q_{niyt}^{\text{dg}}, q_{ijyt}^{\text{tr}}\right\} \succeq 0, \\ \left\{q_{biyt}^{\text{dis}}, q_{biyt}^{\text{ch}}\right\} \succeq 0, \\ \left\{q_{biyt}^{\text{st}}\right\}, \\ \left\{Q_{miy}^{\text{ig,new}}, Q_{niy}^{\text{dg,new}}, Q_{ijy}^{\text{tr,new}}\right\} \succeq 0, \\ \left\{Q_{biy}^{\text{st}^{\text{f}},\text{new}}, Q_{biy}^{\text{st}^{\text{v}},\text{new}}\right\} \succeq 0}} \sum_{i,y,t} \frac{\Delta\ell}{(1{+}r)^y} \Bigg\{ \left(\alpha_{iyt} {-} \frac{\beta_{iyt}}{2} D_{iyt}(.)\right) D_{iyt}(.) {-} \sum_m (1{-}\gamma_{mi}^{\text{ig}}) \frac{\beta_{iyt} {q_{miyt}^{\text{ig}}}^2}{2} {-} \sum_n (1{-}\gamma_{ni}^{\text{dg}}) \frac{\beta_{iyt} {q_{niyt}^{\text{dg}}}^2}{2}$$

$$- \sum_b (1 - \gamma_{bi}^{\text{st}}) \frac{\beta_{iyt} {q_{biyt}^{\text{st}}}^2}{2} - \sum_j (1 - \gamma_{ij}^{\text{tr}}) \frac{\left({\eta_{ij}^{\text{tr}}}^2 \beta_{iyt} + \beta_{jyt}\right) {q_{ijyt}^{\text{tr}}}^2 - \eta_{ij}^{\text{tr}} \left(\beta_{jyt} + \beta_{iyt}\right) q_{ijyt}^{\text{tr}} q_{jiyt}^{\text{tr}}}{2} - \sum_m c_{mi}^{\text{ig}} q_{miyt}^{\text{ig}}$$

$$-\sum_{n} c_{ni}^{\mathrm{dg}} q_{niyt}^{\mathrm{dg}} \Bigg\} - \sum_{i,y} \frac{1}{(1+r)^y} \Bigg\{ \sum_{m} Inv_{miy}^{\mathrm{ig}} Q_{miy}^{\mathrm{ig,new}} + \sum_{n} Inv_{niy}^{\mathrm{dg}} Q_{niy}^{\mathrm{dg,new}} + \sum_{b} Inv_{biy}^{\mathrm{st^v}} Q_{biy}^{\mathrm{st^v,new}} + Inv_{biy}^{\mathrm{st^f}} Q_{biy}^{\mathrm{st^f,new}}$$
$$+ \sum_{j} \frac{Inv_{ijy}^{\mathrm{tr}}}{2} \left(Q_{ijy}^{\mathrm{tr,new}} + Q_{jiy}^{\mathrm{tr,new}} \right) \Bigg\} \quad (15a)$$

s.t.

$$(1), \quad (2), \quad (7b - 7c) \quad \forall m, i, \quad (8b - 8e) \quad \forall n, i, \quad (9b - 9f) \quad \forall b, i, \quad (10b - 10c) \quad \forall i, j \quad (15b)$$

which is subject to the constraints on emission (1) and fast response capacity (2) in addition to the set of constraints in the game model.

The only differences between the KKT conditions of the developed centralized optimization problem and the KKT conditions of our game model, given the orthogonal constraints corresponding to emission (1) and fast response capacity (2) with dual variables of μ_y^{ER} and μ_{iy}^{FR}, that is,

$$\frac{\sum\limits_{i,t} \sum\limits_{n \in \mathcal{N}_i^{\mathrm{dg}}} q_{niyt}^{\mathrm{dg}} EF_{ni}}{\sum\limits_{i,t} \sum\limits_{n \in \mathcal{N}_i^{\mathrm{dg}}} q_{niyt}^{\mathrm{dg}} + \sum\limits_{m \in \mathcal{N}_i^{\mathrm{ig}}} q_{miyt}^{\mathrm{ig}}} \leq \left(1 - \alpha_y^{\mathrm{ER}}\right) EI_{\mathrm{Y_0}}^{\mathrm{CO_2}} \;\; \perp \;\; \mu_y^{\mathrm{ER}} \geq 0,$$
$$\sum_{t} \left(\sum_{n \in \mathcal{N}_i^{\mathrm{dg}}} \alpha_{ni}^{\mathrm{dg,FR}} q_{niyt}^{\mathrm{dg}} + \sum_{b \in \mathcal{N}_i^{\mathrm{st}}} \alpha_{bi}^{\mathrm{st,FR}} q_{biyt}^{\mathrm{dis}} \right) \geq \alpha^{\mathrm{FR}} \sum_{t} \sum_{m \in \mathcal{N}_i^{\mathrm{ig}}} q_{miyt}^{\mathrm{ig}} \;\; \perp \;\; \mu_{iy}^{\mathrm{FR}} \geq 0$$

can be shown as:

(i) the equation (11a) changes to:

$$\Delta l \frac{P_{iyt}(.) - c_{mi}^{\mathrm{ig}} - \beta_{iyt} q_{miyt}^{\mathrm{ig}} \left(1 - \gamma_{mi}^{\mathrm{ig}}\right)}{(1+r)^y} - \mu_{miyt}^{\mathrm{ig}} + \left(1 - \alpha_y^{\mathrm{ER}}\right) EI_{\mathrm{Y_0}}^{\mathrm{CO_2}} \mu_y^{\mathrm{ER}} - \alpha^{\mathrm{FR}} \mu_{iy}^{\mathrm{FR}} \leq 0 \;\; \perp \;\; q_{miyt}^{\mathrm{ig}} \geq 0, \quad (17)$$

(ii) the equation (12a) changes to:

$$\Delta l \frac{P_{iyt}(.) - c_{ni}^{\mathrm{dg}} - \beta_{iyt} q_{niyt}^{\mathrm{dg}} \left(1 - \gamma_{ni}^{\mathrm{dg}}\right)}{(1+r)^y} - \mu_{niyt}^{\mathrm{dg}} + \mu_{niy(t+1)}^{\mathrm{up}} - \mu_{niyt}^{\mathrm{up}} - \mu_{niy(t+1)}^{\mathrm{dn}} + \mu_{niyt}^{\mathrm{dn}} - \mu_{niy}^{\mathrm{dg,RA}} -$$
$$\left(EF_{ni} - \left(1 - \alpha_y^{\mathrm{ER}}\right) EI_{\mathrm{Y_0}}^{\mathrm{CO_2}}\right) \mu_y^{\mathrm{ER}} + \alpha_{ni}^{\mathrm{dg,FR}} \mu_{iy}^{\mathrm{FR}} \leq 0 \;\; \perp \;\; q_{niyt}^{\mathrm{dg}} \geq 0 \quad (18)$$

(iii) the equation (13b) changes to:

$$-\eta_{bi}^{\mathrm{dis}} \mu_{biyt}^{\mathrm{st}} - \mu_{biyt}^{\mathrm{dis}} - \Delta \sum_{t'=t}^{N_T} \mu_{biyt'}^{\mathrm{st,min}} - \mu_{biyt'}^{\mathrm{st,max}} + \mu_{biyt}^{\mathrm{dis/ch}} q_{biyt}^{\mathrm{ch}} + \alpha_{bi}^{\mathrm{st,FR}} \mu_{iy}^{\mathrm{FR}} \leq 0 \perp q_{biyt}^{\mathrm{dis}} \geq 0 \quad (19)$$

Therefore, we match the NE solution of our game-theoretical market expansion model with the solution of this optimization problem, which satisfies the emission and fast response constraints, by designing the tax and subsidy incentive terms.

C. Designing the Tax and Subsidy Incentives

Comparing (11a) with (17), (12a) with (18), and (13b) with (19), we set the tax and subsidy incentives $C_y^{\mathrm{ER,ig}}(.)$, $C_{iy}^{\mathrm{FR,ig}}(.)$, $C_y^{\mathrm{ER,dg}}(.)$, $C_{iy}^{\mathrm{FR,dg}}(.)$, and $C_{iy}^{\mathrm{FR,st}}(.)$ in (7a), (8a), and (9a) in the game problem as following:

$$C_y^{\mathrm{ER,ig}}(.) = \frac{(1+r)^y}{\Delta\ell}\left(1-\alpha_y^{\mathrm{ER}}\right) EI_{\mathrm{Y_0}}^{\mathrm{CO_2}} \mu_y^{\mathrm{ER}^*} \tag{20a}$$

$$C_y^{\mathrm{ER,dg}}(.) = \frac{(1+r)^y}{\Delta\ell}\Big(\left(1-\alpha_y^{\mathrm{ER}}\right) EI_{\mathrm{Y_0}}^{\mathrm{CO_2}} - EF_{ni}\Big) \mu_y^{\mathrm{ER}^*} \tag{20b}$$

where $\mu_y^{\mathrm{ER}^*}$ is the dual variable of the emission reduction constraint (1) at the optimal solution of the centralized problem, $C_y^{\mathrm{ER,ig}}(.)$ is equal to the subsidy the intermittent renewable generator m in region i, which is wind or solar, receives per each MWh electricity generation at period y, and $C_y^{\mathrm{ER,dg}}(.)$ denotes the tax/subsidy the dispatchable generator n in region i pays/receives per each MWh electricity generation at period y; and,

$$C_{iy}^{\mathrm{FR,ig}}(.) = -\frac{(1+r)^y}{\Delta\ell}\alpha^{\mathrm{FR}}\mu_{iy}^{\mathrm{FR}^*} \tag{21a}$$

$$C_{iy}^{\mathrm{FR,dg}}(.) = \frac{(1+r)^y}{\Delta\ell}\alpha_{ni}^{\mathrm{dg,FR}}\mu_{iy}^{\mathrm{FR}^*} \tag{21b}$$

$$C_{iy}^{\mathrm{FR,st}}(.) = \frac{(1+r)^y}{\Delta\ell}\alpha_{bi}^{\mathrm{st,FR}}\mu_{iy}^{\mathrm{FR}^*} \tag{21c}$$

where $\mu_{iy}^{\mathrm{FR}^*}$ is the dual variable of the fast response generation constraint (2) at the optimal solution of the centralized problem, $C_{iy}^{\mathrm{FR,ig}}(.)$ is equal to the fast response tax for intermittent generators, and $C_{iy}^{\mathrm{FR,dg}}(.)$, and $C_{iy}^{\mathrm{FR,st}}(.)$ are equal to the fast response subsidy for dispatchable generators and storage firms, respectively.

Therefore, we can say that the term $\frac{\sum_t \alpha^{\mathrm{FR}}\mu_{iy}^{\mathrm{FR}} q_{miyt}^{\mathrm{ig}}}{Q_{miy}^{\mathrm{ig}}(.)}$ is equal to the fast response capacity tax that in average one MW intermittent generator pays per period y, and the terms $\frac{\sum_t \alpha_{ni}^{\mathrm{dg,FR}}\mu_{iy}^{\mathrm{FR}} q_{niyt}^{\mathrm{dg}}}{Q_{niy}^{\mathrm{dg}}(.)}$, and $\frac{\sum_t \alpha_{bi}^{\mathrm{st,FR}}\mu_{iy}^{\mathrm{FR}} q_{biyt}^{\mathrm{dis}}}{Q_{biy}^{\mathrm{st,f}}(.)}$ are equal to the fast response capacity subsidy that in average one MW dispatchable generator and one MW storage firm receive per period y, respectively.

IV. Case Study and Simulation Results

In this section, we apply our market expansion framework to the Australia's NEM. NEM consists of five loosely interconnected states: South Australia (SA), Queensland (QLD), Tasmania (TAS), Victoria (VIC), and New South Wales (NSW). The investment is calculated every five years from 2017 to 2052 in our model, considering a representative (averaged) 24-hour operation time (load time) horizon. The coefficients α and β in (5) are calibrated based on average levels of historical demand and price recorded in five states of NEM in 2016-2017, with the price and demand error terms of 6.4% and 4.7%, respectively. Dispatchable generators include classical coal, gas, hydro, and biomass plants in addition to the new emerging technology of solar thermal, and the intermittent generators consist of wind farms, PV farms and roof-top PVs. Storage technologies include pump-hydros, cooperatively controlled and non-cooperative batteries. The technology characteristic data and the incumbent capacities of the dispatchable and intermittent generators, storage technologies, and interconnectors existing in NEM are listed in Appendix A.

The investment cost of any technology reduces as time goes on with the given de-escalation rates [31], which are input to our model. Based on the de-escalation rates, the mature generation technologies like coal, gas, biomass and hydro do not show significant investment cost reduction, whereas wind, PV, and solar thermal are expected to have 30%, 42%, and 53% investment cost reduction by 2052, respectively. The largest investment cost reduction is forecast for battery storage technology, which is about 68% by 2052. Note that there is uncertainty about the evolution of technology costs [32], and different technology cost assumptions may lead to dissimilar results. However, we have used the best available estimates and widely accepted parameters in our simulations.

The parameter α^{FR} used in fast response constraint (2) is equal to 0.8 in our simulations, which is the average of proportion coefficients between intermittent and dispatchable electricity in [9], [22]. Note that we can increase the system reliability by increasing the parameter α^{FR}.

A. *Impact of Emission Reduction Policy on Market Expansion*

In our study, the coefficient α^{ER}, is set to force 0% up to 100% emission intensity reduction by 2052 compared to 2017. Fig. 1 compares the net increase or decrease of capacity for generation technologies, Fig. 1(a), and for storage and transmission technologies, Fig. 1(b), by 2052 in NEM, given the emission intensity reduction target. Based on this figure, increasing the emission intensity target up to 45% will not affect the net generation capacity. This is because clean electricity technologies are competitive enough to penetrate and reduce the emission intensity at least by 45% by 2052. However, to achieve a higher level of emission reduction target, it is required to set emission tax/subsidy incentive policies. The emission tax/subsidy incentives lead to accelerate the closure of coal and gas plants, from -10.9 GW and -5.5 GW to -19.9 GW and -8.3 GW, respectively, and the addition of renewable generators, from 9.3 GW to 22.2 GW for dispatchable renewables and from 26.8 GW to 40.8 GW for intermittent renewables, in the network by 2052.

The high penetration of intermittent generation technologies is accompanied by high levels of storage in both forms of pump-hydro and cooperatively controlled batteries, which increase at most by 9.5 GW and 12.1 GW until 2052, respectively, and also high levels of interconnector between states, which increases at most by 3.7 GW until 2052. The non-cooperative batteries, which just make profit from energy arbitrage, cannot compete with cooperatively controlled batteries which make profit from both energy arbitrage and fast response support. In high emission intensity reduction target cases, very low level of investment is made on batteries without fast response provision capability (non-cooperative batteries) in the network.

In the following subsections, we compare our simulation results for just two cases of (i) No Emission Intensity Reduction policy (ii) 80% Emission Intensity Reduction policy in NEM by 2052 (zero emission scenarios in

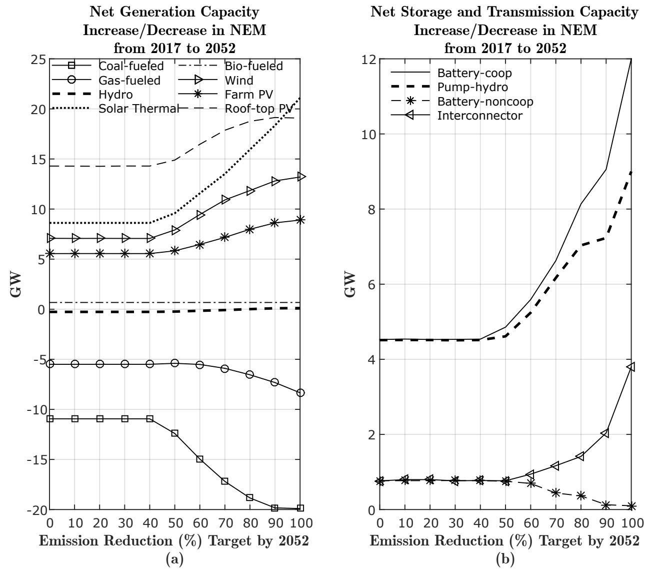

Fig. 1: Net increase/decrease of capacity for (a) generation and (b) storage and transmission technologies by 2052 in NEM for different target levels of emission intensity reduction.

Australia until 2050 and 2070 are discussed in [31]). Note that even in the first case the emission intensity reduces almost by 45%, which means that emission intensity reduction will happen even without any emission policy.

B. Impact of Emission Reduction Policy on Electricity Prices and Demands

The emission intensity reduction target affects the trajectory of electricity prices and demands in NEM during 2017-2052. Fig. 2(a) illustrates the average wholesale prices in NEM by 2052 with and without implementing the emission reduction policy. It can be seen that the market price is extremely high in 2017, which is the consequence of exercising market power by coal and gas generation firms. The price reduction trend continues for the next twenty years, i.e., until 2037. In fact, investment on renewable technologies increases the competition and reduces the prices for that period. Renewable generation firms, due to their sizes, benefit less from market power than conventional generators. By 2037, a large portion of coal power plants are closed down in our model and the cost of installing new generation capacities raises the wholesale prices again during 2037-2052. Surprisingly, in the price declining period, i.e., 2017-2037, imposing the emission intensity reduction policies comparatively lowers the prices by 5%, which is related to the market power level. Penetration of renewables increases the competition (reduces the market power) and leads to lower prices.

Fig. 2(b) compares the average wholesale and net demand levels in NEM by 2052 with and without implementing the emission reduction policy. Note that the net demand includes the roof-top PV generation in addition to the wholesale demand. The divergence of the net and wholesale demand levels is caused by penetration of roof-top PVs in the network. Roof-top PV generation increases by 3.93 times in No Emission Reduction Policy case and by 4.84 times in 80% Emission Reduction Policy case until 2052, which shows that roof-top PV is competent enough to penetrate enormously by 2052 with or without emission incentive policy.

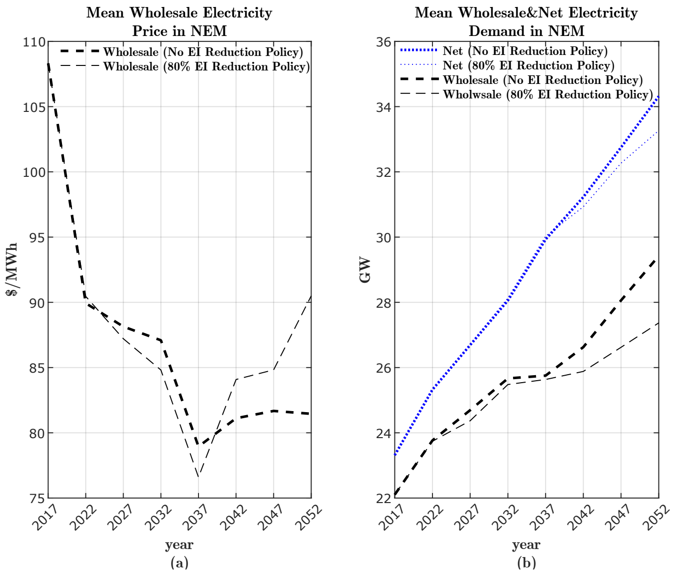

Fig. 2: The average yearly (a) wholesale prices and (b) net and wholesale demands in NEM, without or with emission reduction policy (net demand =wholesale demand + roof-top PV).

C. Carbon Tax&Subsidy Design

We design the emission incentives based on the dual variable of the emission intensity constraint, which is called carbon price, at the NE point in our model. Implementing 80% Emission Intensity Reduction policy, the emission intensity must uniformly decrease from the base year level of 0.727 $\mathrm{tonne_{CO_2}/MWh_e}$ in 2017 to 0.145 $\mathrm{tonne_{CO_2}/MWh_e}$ in 2052. Fig. 3 (a) shows the calculated carbon price at different years to reach 80% emission intensity reduction by 2052. The carbon price moves upward in the beginning stage, up to year 2032, then decreases during 2032-2042, and goes up again at the final stage, 2042-2052. The closure of coal and gas power plants, which are at their end of life, mostly happens during 2032-2042, which reduces the emission intensity and carbon price level. However, higher levels of carbon price is calculated in our model to achieve higher levels of emission intensity reduction at the final stage, regarding the uniform reduction of emission intensity from 2017 to 2052.

Fig. 3 (b) indicates the average amounts of tax and subsidy that any type of generator pays or receives each year based on their electricity generation emission intensity and the calculated carbon price of that year. As coal-fueled generators have emission intensities much higher than the emission intensity target levels, they always pay carbon tax in the market. The gas-fueled generators have lower emission intensities and do not pay significant carbon penalty until 2042. The renewable generators, including wind, PV, solar thermal, bio-fueled, and hydro, receive the carbon subsidy in the market, as their generation emission intensity is zero. One kW capacity of solar thermal and bio-fueled generators are more efficient in reducing the emission intensity than one kW of wind, PV or even hydro, and thus receive higher emission subsidy in average.

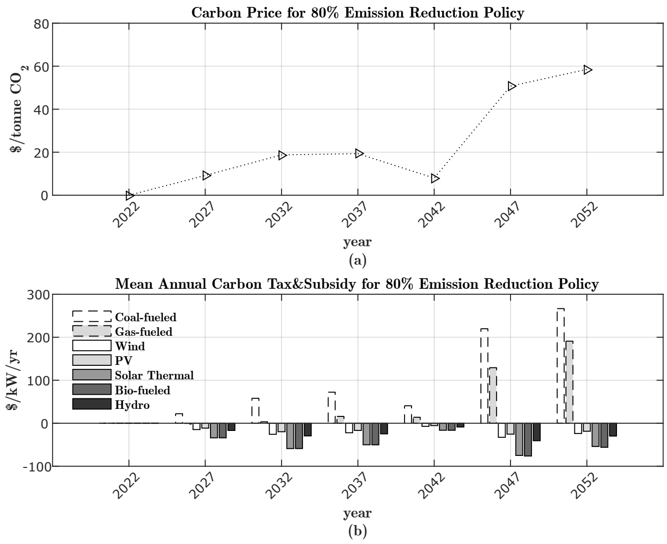

Fig. 3: The trajectory of (a) carbon price, (b) carbon tax (positive) and subsidy (negative) of different generation types during 2017-2052.

D. Fast Response Capacity Tax&Subsidy Design

The other tax and subsidy incentive is calculated based on the dual variable of the fast response dispatchable generation constraint at the NE point in our model. Intermittent generators, i.e., wind and PV, are vulnerable to generation fluctuation due to wind and solar energy availability. Therefore, there must be adequate fast response generation capacity to dispatch even out of merit, i.e., even when their marginal cost of generation is above the market price, if wind or solar is lacking. As fast response generators may dispatch out of merit, they need to be subsidized. The subsidy is provided by taxing the intermittent generators. Fig. 4 indicates the level of fast response tax and subsidy for different generation types during 2017-2052, with and without emission intensity reduction policy. It can be seen that implementing the emission reduction policy, which leads to higher levels of intermittent generation in the market, we calculate higher amounts of fast response tax and subsidy for all generators. Moreover, the subsidy level is not the same for different generation types. One kW pump-hydro receives higher subsidy for fast response provision than one kW battery as pump-hydros generally have larger energy storage tanks (kWh). However, the battery's fast response subsidy becomes more than the pump-hydro's in 2052 due to the decline in investment cost of the battery tanks. The subsidy on hydro plants uniformly increases by time, but the subsidy on gas-fueled plants increases significantly after 2042, as they have to pay considerable amounts of emission tax at those times.

V. Discussion

In this paper, we found the NE in our game-theoretical market model without the conventional method of concurrently solving the KKT conditions of all players in the game, e.g. [24], [33]. Alternatively, without writing the KKT equations, we solve the Cournot-based electricity market expansion model as a centralized optimization

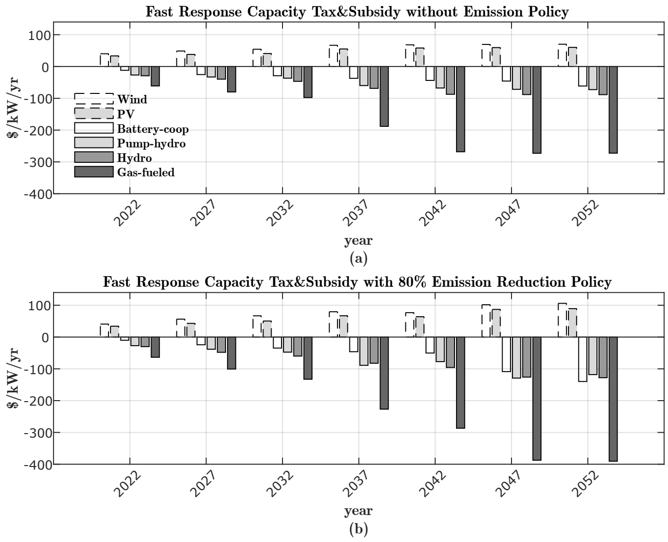

Fig. 4: The trajectory of fast response capacity tax (positive) and subsidy (negative) for (a) No Emission Reduction policy, (b) 80% Emission Intensity Reduction policy.

problem and design the tax and subsidy incentive policies. Our main findings based on our numerical results can be summarized as:

- Emission intensity reduction policies do not necessarily increase the average electricity prices all the times. Considering the Emission Intensity Reduction policy in our model, we calculated lower prices relative to No Emission Reduction policy scenario in the market until 2042. We also found that the price increase due to implementing the emission policies after 2042 happens at off peak times and even slightly reduces the peak time prices. This discussion is similar to the recent findings in [22].
- It is observed in our simulations that the retirement of the incumbent coal-fueled and gas-fueled generators reduces the designed carbon prices and subsequently the emission incentive policy levels in 2042. Thereafter, carbon price rises again to retain the emission intensity reduction trend in the market. It indicates the necessity of designing dynamic emission policies in electricity markets.
- The incentive policies of fast response capacity tax and support, which penalize the intermittent generators and subsidize the fast response capacities, can lead to higher reliability levels in the network. Gradual retirement of the incumbent gas-fueled plants and penetration of intermittent generators necessitate higher levels of subsidy to ensure existence of enough fast response capacity in the market.
- Although the emission and fast response policies considered in our model are based on the policies suggested in [22] for Australia, we can design different types of emission reduction policies, such as C&T carbon policy or RPS, by updating the emission constraint (1), and design different reliability policies by updating the flexibility constraint (2).

Lastly, the high level of investment on dispatchable renewable capacity, like solar thermal, which may have heat energy storage system or may be a hybrid system that use other fuels during periods of low solar radiation, and battery storage can also prevent the inertia and frequency response problems in electricity networks with high level of intermittent generation, as discussed in [4].

APPENDIX A
TECHNOLOGY CHARACTERISTICS

In this section, all financial and technical information on intermittent and dispatchable generators, storage technologies and Interconnectors are from [9], [31], [34].

TABLE I: Financial and Technical Information on Intermittent Generators in NEM.

Generator Type:	wind Turbine	Farm PV	Roof-top PV
Q^{ig}_{2017} (GW)	3.733	0.356	4.826
$\tilde{Inv}^{\text{ig}}_{(a),(b)}$ ($\frac{\$}{\text{kW}}$)	$2400^{(1.5\%)}$	$2190^{(3.5\%)}$	$2100^{(3.5\%)}$
c^{ig} ($\frac{\$}{\text{MWh}}$)	5	2	3
PL^{ig} (yr)	25	20	20
$\bar{C}^{\text{ig}}$ (GW)	n.a	n.a	24.266

(a) Yearly maintenance cost is approximated by 1 percent of investment cost for all generation, storage and transmission technologies in our calculations.
(b) Investment cost de-escalator rate (%). After 2037 the de-escalator used for wind and all the different solar technologies drops to 0.3% since they are considered mature technologies.

TABLE II: Financial and Technical Information on Synchronous Generators in NEM.

Plant:	Q^{dg}_{2017} (GW)	$\tilde{Inv}^{\text{dg}}$ ($\frac{\$}{\text{kW}}$)$^{(a)}$	c^{dg} ($\frac{\$}{\text{MWh}}$) operation+fuel	PL^{dg} (yr)	R^{up}, R^{dn} ($\frac{\%}{\text{hr}}, \frac{\%}{\text{hr}}$)	A^{dg} (%)	EF ($\frac{\text{t}_{\text{CO}_2}}{\text{MWh}}$)	RA^{dg} ($\frac{\text{TWh}}{\text{yr}}$)	$\alpha^{\text{dg,FR}} \in \{0,1\}$
Black Coal	18.440	$4285^{(0.1\%)}$	3+18	50	10	75	1	n.a	0
Brown Coal	4.730	$5715^{(0.1\%)}$	3+16.5	50	10	75	1.2	n.a	0
Thermal Gas	1.837	$1910^{(0.2\%)}$	7.5+84	30	10	75	0.62	n.a	0
CC Gas Turbine	3.402	$2100^{(0.2\%)}$	6.1+56	30	10	75	0.41	n.a	0
OC Gas Turbine	6.076	$1720^{(0.2\%)}$	9+84	30	100	75	0.62	n.a	1
Solar Thermal with Storage	0	$8500^{(2.5\%)}$	25+0	35	10	75	0	n.a	0
Biomass	1.014	$6500^{(0.5\%)}$	8+42	30	10	75	0	7.8	0
Hydro	5.711	$3600^{(0.5\%)}$	5+0	35	100	70	0	23.96	1

(a) Capital cost de-escalator rate (%). After 2037 the de-escalator used for solar thermal drops to 0.3%.

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TABLE III: Financial and Technical Information on Storage Technologies in NEM.

Storage Type:	Pump-hydro	Coop. battery	Non-coop. battery
$Q^{\mathrm{st,f}}_{2017}$ (GW)	2160	0	0
$Q^{\mathrm{st,v}}_{2017}$ (GWh)	21600	0	0
$\tilde{Inv}^{\mathrm{st,f}}$ $(\frac{\$}{\mathrm{kW}})^{(\mathrm{a})}$	$800^{(0.5\%)}$	$225^{(3.1\%)}$	$150^{(3.1\%)}$
$\tilde{Inv}^{\mathrm{st,v}}$ $(\frac{\$}{\mathrm{kWh}})$	$70^{(0.5\%)}$	$225^{(3.1\%)}$	$225^{(3.1\%)}$
$PL^{\mathrm{st,f}}$ (yr)	30	10	10
$PL^{\mathrm{st,v}}$ (yr)	50	10	10
η^{dis},η^{ch} (%,%)	85,85	95,95	95,95
A^{st} (%)	70	90	90
$\alpha^{\mathrm{dg,FR}} \in \{0,1\}$	1	1	0

(a) Investment cost de-escalator rate (%).

TABLE IV: Financial and Technical Information on Interconnectors in NEM.

Interconnector:	SA-VIC	TAS-VIC	VIC-NSW	QLD-NSW
Q^{tr}_{2017} (GW) Forward	510	478	150	800
Q^{tr}_{2017} (GW) Reverse	680	594	500	1400
$\tilde{Inv}^{\mathrm{tr}}$ $(\frac{\$}{\mathrm{kW}})$	1000	1600	700	1100
PL^{tr} (yr)	50	50	50	50
η^{tr} (%)	95	95	95	95
A^{tr} (%)	70	70	70	70

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