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 novel framework to design interactive tax/subsidy incentives on both emission reduction and resource adequacy in competitive electricity markets as a game model. In our model, market participants decide on their capacity expansion/retirement strategies considering the impact of designed incentive schemes on their long-term operation such that the desired levels of emission reduction and fast response generation are achieved in the network. The simulation results for Australia's electricity market during 2017-2052, indicate the necessity of incentive policies, in spite of the cost reduction trajectory for renewable technologies, to reach the emission intensity reduction above 45% in the market by 2052. In 80% emission intensity reduction scenario, the designed incentive schemes highly encourage the investment on dispatchable renewables, +17 GW, storage technologies, +15.7 GW, and transmission lines, +1.6 GW, to support high additional penetration of Variable Renewable Energy, wind and solar, +39 GW, which paves the way to transition to a green and reliable electricity market.

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).
y	Investment period.
t	load time.

Parameters

α_{iyt}	Intercept of the inverse demand function ($/MWh).
β_{iyt}	Slope of the inverse demand function ($/MWh/MW).
$EI_{Y_0}^{\mathrm{CO_2}}$	$\mathrm{CO_2}$ Emission intensity at base year Y_0 ($\mathrm{t_{CO_2}/MWh}$).
EF_{ni}	Emission factor of the dispatchable generator ($\mathrm{t_{CO_2}/MWh}$).
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^{old}	Old capacity of any generation, storage and transmission technology still working at y (MW or MWh).
$\bar{Q}_{mi}^{\mathrm{ig}}$	Maximum potential capacity of the intermittent generator (MW).
c_{mi}^{ig}	Unit operation cost of the intermittent generator ($/MWh).
c_{ni}^{dg}	Unit operation and fuel cost of the dispatchable generator ($/MWh).
$\gamma_{mi}^{\mathrm{ig}}$	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 ($\mathrm{MWh}/\Delta y$).
η_{bi}^{ch},η_{bi}^{dis}	Charge and discharge efficiencies of the

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	storage (%).
Inv^{ig}_{miy}	Unit investment cost of the intermittent generator (\$/MW).
Inv^{dg}_{niy}	Unit investment cost of the dispatchable generator (\$/MW).
$Inv^{\mathrm{st^f}}_{biy}$	Unit investment cost of the storage on flow capacity (\$/MW).
$Inv^{\mathrm{st^v}}_{biy}$	Unit investment cost of the storage on volume capacity (\$/MWh).
Inv^{tr}_{ijy}	Unit investment cost of the transmission line (\$/MW).
PL	Plant life (year).
r	Discount rate (%).

Variables

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

Functions

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

1 INTRODUCTION

The electricity markets are undergoing a significant transition. Renewable energy and clean energy play an important role in our modern electricity networks. However, many new generation technologies do not inherently provide system services that were previously provided as a consequence of energy provision [1], which results in the necessity of existing enough dispatchable capacity to integrate high levels of Variable Renewable Energy (VRE) in the market.

This paper presents a novel incentive design framework to quantify the required tax and subsidy levels on emission and fast response capacity to ensure emission reduction and resource adequacy in competitive electricity markets. While many studies have investigated various aspects of this problem, very few are quantitative and take into account the competitive behaviour of market players and the impact of incentive policies on their decisions. Our framework achieves this and presents quantitative results by adopting a game-theoretic approach. Specifically, the dual variables of emission and fast response constraints at the solution of the introduced Cournot-based electricity market model quantify the tax and subsidy incentives as a scientific foundation for future policies.

We highlight in Subsection 1.2 how our work differs from previous works. It is discussed that the schemes designed with least cost generation expansion models might fail to reach the emission reduction and resource adequacy targets, as they do not take strategically competitive behaviours of market players into account. Moreover, the emission reduction policies designed with competitive market expansion models have not taken resource adequacy policy into account. Our model designs interactive incentives on both emission reduction and resource adequacy considering the strategic behaviours of the players in competitive electricity markets. We illustrate this novel approach numerically using Australia as a use case scenario.

1.1 The Importance of Incentive Policies in Electricity Sector

Integration of variable and distributed energy resources provides opportunities for clean and low cost generation [2]. Although the decline in technology cost enables renewables to compete with fossil-fueled plants in electricity generation, the emission reduction incentives can accelerate the ongoing transition toward a low carbon market [3]. 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) [4], and the US Renewable Portfolio Standards (RPS) require that load serving entities meet a minimum portion of their load with renewable electricity [5].

Note that high penetration of variable renewable energy in an electricity network can pose challenges to system reliability [6] and increase the renewable integration cost [7]. Additional fast response dispatchable capacity must be introduced to the system to complement an increasing proportion of intermittent renewable generators such as wind and solar photovoltaic. However, it might not be profitable to make new dispatchable capacities because of missing money problem [8], and new obligations might be required to ensure resource adequacy and reliability in the network. 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 [9].

This paper develops a quantitative framework for designing tax/subsidy incentives on emission and fast response capacity in competitive electricity markets as a game model. 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 electricity market as the case study.

1.2 Related Works

The problem of policy making for emission abatement and renewable integration in electricity industry has been studied in [10]–[15], using least cost market expansion models, and in [16]–[19], using strategically competitive market expansion models. However, the problem of designing interactive incentive policies on both emission reduction and fast response dispatchable capacity support in competitive electricity markets has not been investigated in the literature.

Least cost generation expansion models have been used to study different emission reduction and renewable integration strategies in electricity networks, such as: (i) a power generation expansion model is developed to find the optimal mix of the thermal generating units with emission control, regarding to the incorporated environmental costs, in [10]; (ii) the optimal mix of electricity supply sources at minimum cost is determined considering specified $\mathrm{CO_2}$ emission targets in [11]; (iii) the potential of biomass power generation and its impact on generation expansion planning as well as carbon emission mitigation are estimated in [12]; (iv) instead of bounding the carbon emission, optimal incentive rates are designed for targeted penetration of renewable integration in a generation expansion model in [13]; (v) effective and efficient incentive policies for targeted renewable penetration are designed by minimizing the total policy intervention in generation expansion planning in [15]. However, the designed scheme policies might fail to incetivize the investment on desired generation fleet to reach the emission reduction targets, as least cost generation expansion models do not take strategically competitive behaviour of market players into account.

Competitive electricity market expansion models have been developed to study the integration of renewables and emission reduction in deregulated electricity markets, such as: (i) the effect of intermittently renewable energy, PV technology, on generation capacity mix and prices in deregulated electricity markets is assessed in [16]; (ii) the efficiency of mandatory renewable targets and technology standards with emission trading scheme is compared using a market-led expansion model in [17]; (iii) allocation of free initial emission permits to offset the profit reduction of emission-intensive industries is discussed to analyze the political feasibility of an emission trading scheme in [18]; (iv) the impact of penalizing carbon emission on generation capacity planning in a single-node electricity market is also studied in [19], which discusses that the dual variable of the emission target constraint can be interpreted as the carbon price in the market. However, the necessity of incentive for installing dispatchable capacities has not been discussed in the emission reduction scheme designs in these works.

The electricity market expansion planning also requires 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 a least-cost generation expansion model in [20]. Market intervention to install dispatchable capacity, such as storage, is suggested to limit the price volatility in competitive electricity markets in [21], [22]. Capacity market beside the energy market is suggested to incentivize the right level of dispatchable capacity investment in competitive electricity markets in [23]. However, to the best of our knowledge, the interactive incentive designing on both emission reduction and resource adequacy in competitive electricity markets has not been studied before.

The emission reduction and resource adequacy scheme policies are designed in our paper based on *Clean Energy Target* policy suggested in *Blueprint for the Future* report [24]. While reducing the emission intensity in Australia, it suggests to limit the total variable renewable energy generation to a proportion of dispatchable generation, which provides incentives to install minimum required dispatchable capacity in the network.

1.3 Contributions

This paper proposes a quantitative tax and subsidy design framework to reach policy makers' emission reduction and reliability goals in competitive electricity markets. It aims at calculating model-based tax and subsidy levels which incentivize market players to invest on clean and flexible form of generation to ensure both emission reduction and resource adequacy in the market. The main contributions of this paper can be summarized as:

1) A quantitative incentive design framework is proposed as a game model to calculate the required tax and subsidy levels on emission and fast response capacity to ensure emission reduction and resource adequacy in competitive electricity markets.
2) The competitive behaviour of market players and the impact of incentive policies on their decisions are considered in our developed game-theoretical

multi-region multi-period Cournot-based electricity market expansion model.

3) Our game model is solved as a centralized optimization problem, instead of dealing with the cumbersome method of writing the KKT equations and solving the game as a Mixed Complementarity Problem as in [25], [26].
4) The dual variables of emission and fast response constraints at the solution of the centralized optimization problem are used to design the tax and subsidy incentive policies.

Under the proposed framework, the required tax and subsidy amounts on emission and fast response dispatchable generation are calculated for Australia's NEM such that the emission intensity reduction 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 tax and subsidy design framework for competitive electricity markets is formulated as a game model in Section 2. The conversion of the game model to a centralized optimization problem and the solution method are presented in Section 3. The simulation results are presented in Section 4. The conclusion remarks are discussed in Section 5.

2 Tax and Subsidy Design Framework for Competitive Electricity Markets

In this section, we develop a tax and subsidy design framework to ensure long-term emission reduction and resource adequacy in an electricity market including competitive players as a Cournot-based game-theoretical model. The game players consist of generation, storage and transmission firms, which are introduced in detail in Section 2.3. The players trade electricity in a multi-region energy-only wholesale electricity market. Let $\mathcal{N}_i^{\text{ig}}$ be the set of intermittent generators, such as wind/PV farms and roof-top PVs, located in region i, $\mathcal{N}_i^{\text{dg}}$ be the set of dispatchable generators, such as coal, gas, hydro and solar thermal power plants, located in region i, $\mathcal{N}_i^{\text{st}}$ be the set of storage firms, such as pump-hydros and batteries (cooperatively controlled or non-cooperative), located in region i, and $\mathcal{N}_i^{\text{tr}}$ be the set of transmission lines connected to region i.

Our developed game model calculates the tax/subsidy levels considering their impacts on long-term behaviours of market players. At the NE solution of the game, in addition to the tax/subsidy levels, the capacity investment strategies of the firms, their bidding strategies as well as the equilibrium nodal prices are calculated. The tax/subsidy incentives on emission and fast response capacity in the market are designed in such a way that the constraints on emission reduction and fast response capacity are satisfied.

2.1 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:

$$\frac{\sum\limits_{i,t} \sum\limits_{n \in \mathcal{N}_i^{\text{dg}}} q_{niyt}^{\text{dg}} EF_{ni}}{\sum\limits_{i,t} \sum\limits_{n \in \mathcal{N}_i^{\text{dg}}} q_{niyt}^{\text{dg}} + \sum\limits_{m \in \mathcal{N}_i^{\text{ig}}} q_{miyt}^{\text{ig}}} \leq \left(1 - \alpha_y^{\text{ER}}\right) EI_{Y_0}^{\text{CO}_2} : \mu_y^{\text{ER}} \; \forall y \tag{1}$$

where $EI_{Y_0}^{\text{CO}_2}$ is the 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 the desired level of emission intensity, as shown in Section 3.3.

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 proportion of total VRE generation to the fast response generation during each investment period to ensure resource adequacy in the network as:

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

where α^{FR} is the fast response proportion coefficient, $\alpha_{ni}^{\text{dg,FR}}$ 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, $\alpha_{bi}^{\text{st,FR}}$ 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 3.3 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 [27].

2.2 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 still working at period y, 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:

$$Q_y(Q^{\text{new}}_{y'\leq y}) = \sum_{y'=\max(1,y-PL+1)}^{y} Q^{\text{new}}_{y'} + Q^{\text{old}}_{y} \quad (3)$$

where PL denotes the plant life of the corresponding technology of the firm. 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 do not take capacity retirement for new invested technologies into account . Market expansion modeling with annualized investment cost, e.g., [28], is the simplified version of investment cost modeling and might not cover all investment options. Instead of using the annualized investment cost, we modify the actual investment cost and consider the depreciated value of the new installed capacities in our study as modified investment cost:

$$Inv_y = \sum_{y'=1}^{\min(PL,N_Y-y+1)} \frac{X}{(1+r)^{y'}} \tilde{Inv} \quad (4)$$

$$\text{given :} \quad \sum_{y'=1}^{PL} \frac{X}{(1+r)^{y'}} = 1 \rightarrow X = \frac{r(1+r)^{PL}}{(1+r)^{PL}-1}$$

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. The function $\frac{X\tilde{Inv}}{(1+r)^{y'}}$ is equal to the depreciation of the investment during the year y' after installation. 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 approximately $\frac{1}{4}$ 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.

2.3 Competitive Market Expansion Model with Tax/Subsidy Incentives

In this subsection, we introduce the long-term competition game which is developed to design tax and subsidy incentives in the market. 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:

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

$$D_{iyt} = \sum_{m\in\mathcal{N}_i^{\text{ig}}} q^{\text{ig}}_{miyt} + \sum_{n\in\mathcal{N}_i^{\text{dg}}} q^{\text{dg}}_{niyt} + \sum_{b\in\mathcal{N}_i^{\text{st}}} q^{\text{st}}_{biyt} + \sum_{j\in\mathcal{N}_i^{\text{tr}}} q^{\text{tr}}_{ijyt} \quad \forall i,y,t \quad (6)$$

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^{st}_{biyt} is the electricity flow from storage firm b in region i, and q^{tr}_{ijyt} 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 total electricity consumption, 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 price taker 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 3.3 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.

2.3.1 Intermittent Generation Firms

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

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

$$\frac{+TS^{\text{ig}}_{miyt}(.)}{} - \sum_{y} \frac{Inv^{\text{ig}}_{miy} Q^{\text{ig,new}}_{miy}}{(1+r)^y} \quad (7a)$$

s.t.

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

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

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 $\gamma^{\mathrm{ig}}_{mi}$, the mth intermittent generation firm in region i behaves strategically or in a regulated manner. The firm acts strategically when $\gamma^{\mathrm{ig}}_{mi}$ is zero or acts as a regulated firm when $\gamma^{\mathrm{ig}}_{mi}$ is one. Considering the market efficiency term, $\frac{\beta_{iyt} {q^{\mathrm{ig}}_{miyt}}^2}{2}$, 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 $C^{\mathrm{ER,ig}}_{y}(.)$, and the cost due to intermittent electricity generation tax $C^{\mathrm{FR,ig}}_{y}(.)$. The constraint (7b) considers the regional intermittent energy availability coefficient in load time t, A^{ig}_{mit}, and the constraint (7c) limits the capacity installation to the maximum potential capacity, $\bar{Q}^{\mathrm{ig}}_{mi}$, e.g., the limit on available area for PV installation.

2.3.2 *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 $TS^{\mathrm{dg}}_{niyt} = \left(C^{\mathrm{ER,dg}}_{y}(.) + C^{\mathrm{FR,dg}}_{iy}(.)\right) q^{\mathrm{dg}}_{niyt}$:

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

s.t.

$$q^{\mathrm{dg}}_{niyt} \le A^{\mathrm{dg}}_{ni} Q^{\mathrm{dg}}_{niy}(.) \ : \ \mu^{\mathrm{dg}}_{niyt} \quad \forall y,t \tag{8b}$$

$$q^{\mathrm{dg}}_{niyt} - q^{\mathrm{dg}}_{niy(t-1)} \le R^{\mathrm{up}}_{ni} A^{\mathrm{dg}}_{ni} Q^{\mathrm{dg}}_{niy}(.) \ : \ \mu^{\mathrm{dg,up}}_{niyt} \ \forall y,t \tag{8c}$$

$$q^{\mathrm{dg}}_{niy(t-1)} - q^{\mathrm{dg}}_{niyt} \le R^{\mathrm{dn}}_{ni} A^{\mathrm{dg}}_{ni} Q^{\mathrm{dg}}_{niy}(.) \ : \ \mu^{\mathrm{dg,dn}}_{niyt} \ \forall y,t \tag{8d}$$

$$\sum_{t} q^{\mathrm{dg}}_{niyt} \le RA^{\mathrm{dg}}_{niy} \ : \ \mu^{\mathrm{dg,RA}}_{niy} \ \forall n,i,y \tag{8e}$$

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

2.3.3 *Storage Firms*

The strategy of the bth storage firm, i.e., pump-hydro, or cooperatively controlled or non-cooperative batteries (cooperative batteries are orchestrated 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 $TS^{\mathrm{st}}_{biyt} = C^{\mathrm{FR,st}}_{iy}(.) q^{\mathrm{dis}}_{biyt}$:

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

s.t.

$$q^{\mathrm{st}}_{biyt} = \eta^{\mathrm{dis}}_{bi} q^{\mathrm{dis}}_{biyt} - \frac{q^{\mathrm{ch}}_{biyt}}{\eta^{\mathrm{ch}}_{bi}} \ : \ \mu^{\mathrm{st}}_{biyt} \quad \forall y,t \tag{9b}$$

$$q^{\mathrm{dis}}_{biyt} \le A^{\mathrm{st}}_{bi} Q^{\mathrm{st^f}}_{biy}(.) \ : \ \mu^{\mathrm{dis}}_{biyt} \quad \forall y,t \tag{9c}$$

$$q^{\mathrm{ch}}_{biyt} \le A^{\mathrm{st}}_{bi} Q^{\mathrm{st^f}}_{biy}(.) \ : \ \mu^{\mathrm{ch}}_{biyt} \quad \forall y,t \tag{9d}$$

$$0 \le \sum_{t'=1}^{t} \left(q^{\mathrm{ch}}_{biyt'} - q^{\mathrm{dis}}_{biyt'}\right)\Delta \le A^{\mathrm{st}}_{bi} Q^{\mathrm{st^v}}_{biy}(.) : \mu^{\mathrm{st,min}}_{biyt}, \mu^{\mathrm{st,max}}_{biyt} \ \forall y,t \tag{9e}$$

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

where $Q^{\mathrm{st^v,new}}_{biy}$ and $Q^{\mathrm{st^f,new}}_{biy}$ are the new volume and flow capacity (variable), and $Q^{\mathrm{st^v}}_{biy}(.)$ and $Q^{\mathrm{st^f}}_{biy}(.)$ 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 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.

2.3.4 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:

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

s.t.

$$q^{\mathrm{tr}}_{kk'yt} = -q^{\mathrm{tr}}_{k'kyt} \ : \ \mu^{\mathrm{tr}}_{kk'yt} \quad \forall k, k' \in \{i,j\} \ \& \ \forall y, t \quad (10b)$$

$$q^{\mathrm{tr}}_{kk'yt} \leq A^{\mathrm{tr}}_{kk'}Q^{\mathrm{tr}}_{kk'y}(.) \ : \ \mu^{\mathrm{tr,cap}}_{kk'yt} \quad \forall k, k' \in \{i,j\} \ \& \ \forall y, t \quad (10c)$$

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 term $P_{iyt}(.)q^{\mathrm{tr}}_{ijyt} + P_{jyt}(.)q^{\mathrm{tr}}_{jiyt}$ in (10a) is the electricity profit of transmitting electricity between regions i and j, the term $\gamma^{\mathrm{tr}}_{ij}\frac{\beta_{iyt}}{2}{q^{\mathrm{tr}}_{ijyt}}^2 + \gamma^{\mathrm{tr}}_{ji}\frac{\beta_{jyt}}{2}{q^{\mathrm{tr}}_{jiyt}}^2$ denotes the regulation surplus and the last term is the total investment cost of new capacities, with unitary investment cost of Inv^{tr}_{ijy} ($Inv^{\mathrm{tr}}_{ijy} = Inv^{\mathrm{tr}}_{jiy}$). Depending on the binary parameter $\gamma^{\mathrm{tr}}_{ij}$ ($\gamma^{\mathrm{tr}}_{ij} = \gamma^{\mathrm{tr}}_{ji}$), 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. Note that the electricity markets with regulated transmission lines are discussed as *electricity markets with transmission constraints* in the literature, e.g., [25], [29], [30]. The constraint (10b) ensures that transmission flow on both directions of the line is identical in our model, and the constraint (10c), in order to consider the congestion in the transmission network, limits the electricity flow to the capacity of transmission lines with availability coefficient A^{tr}_{ij}.

3 Solution Methodology

In this section, we first provide a game-theoretic analysis of the long-term competition 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.

3.1 Game-theoretic Analysis of the Long-Term Competition Problem

To solve the long-term competition 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 [31] 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.

3.1.1 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 ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

$$\Delta l \frac{P_{iyt}(.) - c^{\mathrm{ig}}_{mi} - \left(1 - \gamma^{\mathrm{ig}}_{mi}\right)\beta_{iyt}q^{\mathrm{ig}}_{miyt} + C^{\mathrm{ER,ig}}_{y}(.) + C^{\mathrm{FR,ig}}_{iy}(.)}{(1+r)^y}$$
$$-\mu^{\mathrm{ig}}_{miyt} \leq 0 \ \perp \ q^{\mathrm{ig}}_{miyt} \geq 0 \quad (11a)$$

$$\frac{-Inv^{\mathrm{ig}}_{miy}}{(1+r)^y} - \sum_{y'=y}^{\min(N_Y, y+PL^{\mathrm{ig}}_{mi}-1)} \left(\mu^{\mathrm{ig},\bar{\mathrm{Q}}}_{miy'} - \sum_{t} A^{\mathrm{ig}}_{mit}\mu^{\mathrm{ig}}_{miy't}\right) \leq 0$$
$$\perp \ Q^{\mathrm{ig,new}}_{miy} \geq 0 \quad (11b)$$

$$q^{\mathrm{ig}}_{miyt} \leq A^{\mathrm{ig}}_{mit}Q^{\mathrm{ig}}_{miy}(.) \ \perp \ \mu^{\mathrm{ig}}_{miyt} \geq 0 \quad (11c)$$

$$Q^{\mathrm{ig}}_{miy}(.) \leq \bar{Q}^{\mathrm{ig}}_{mi} \ \perp \ \mu^{\mathrm{ig},\bar{\mathrm{Q}}}_{miyt} \geq 0 \quad (11d)$$

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

3.1.2 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 ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

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

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

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

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

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

$$\sum_{t} q^{\mathrm{dg}}_{niyt} \leq RA^{\mathrm{dg}}_{niy} \ \perp \ \mu^{\mathrm{dg,RA}}_{niy} \geq 0 \quad (12f)$$

3.1.3 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 ($t \in \{1, ..., N_T\}$; $y \in \{1, ..., N_Y\}$):

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

$$\Delta l\frac{C_y^{\mathrm{FR,st}}(.)}{(1+r)^y}-\eta_{bi}^{\mathrm{dis}}\mu_{biyt}^{\mathrm{st}}-\mu_{biyt}^{\mathrm{dis}}-\Delta\sum_{t'=t}^{N_T}\mu_{biyt'}^{\mathrm{st,min}}-\mu_{biyt'}^{\mathrm{st,max}}$$
$$+\mu_{biyt}^{\mathrm{dis/ch}}q_{biyt}^{\mathrm{ch}}\leq 0\ \perp\ q_{biyt}^{\mathrm{dis}}\geq 0 \quad (13b)$$

$$\frac{\mu_{biyt}^{\mathrm{st}}}{\eta_{bi}^{\mathrm{ch}}}-\mu_{biyt}^{\mathrm{ch}}+\Delta\sum_{t'=t}^{N_T}\mu_{biyt'}^{\mathrm{st,min}}-\mu_{biyt'}^{\mathrm{st,max}}+\mu_{biyt}^{\mathrm{dis/ch}}q_{biyt}^{\mathrm{dis}}\leq 0$$
$$\perp\ q_{biyt}^{\mathrm{ch}}\geq 0 \quad (13c)$$

$$\frac{-Inv_{biy}^{\mathrm{st^v}}}{(1+r)^y}+\sum_t A_{bi}^{\mathrm{st}}\sum_{y'=y}^{\min(N_Y,y+PL_{bi}^{\mathrm{st^v}}-1)}\mu_{biy't}^{\mathrm{st,max}}\leq 0\perp Q_{biy}^{\mathrm{st^v,new}}\geq 0 \quad (13d)$$

$$\frac{-Inv_{biy}^{\mathrm{st^f}}}{(1+r)^y}+\sum_t A_{bi}^{\mathrm{st}}\sum_{y'=y}^{\min(N_Y,y+PL_{bi}^{\mathrm{st^f}}-1)}\mu_{biy't}^{\mathrm{dis}}+\mu_{biy't}^{\mathrm{ch}}\leq 0$$
$$\perp\ Q_{biy}^{\mathrm{st^f,new}}\geq 0 \quad (13e)$$

$$q_{biyt}^{\mathrm{st}}=\eta_{bi}^{\mathrm{dis}}q_{biyt}^{\mathrm{dis}}-\frac{q_{biyt}^{\mathrm{ch}}}{\eta_{bi}^{\mathrm{ch}}} \quad (13f)$$
$$q_{biyt}^{\mathrm{dis}}\leq A_{bi}^{\mathrm{st}}Q_{biy}^{\mathrm{st^f}}(.)\ \perp\ \mu_{biyt}^{\mathrm{dis}}\geq 0 \quad (13g)$$
$$q_{biyt}^{\mathrm{ch}}\leq A_{bi}^{\mathrm{st}}Q_{biy}^{\mathrm{st^f}}(.)\ \perp\ \mu_{biyt}^{\mathrm{ch}}\geq 0 \quad (13h)$$
$$0\leq\sum_{t'=1}^{t}\left(q_{biyt'}^{\mathrm{ch}}-q_{biyt'}^{\mathrm{dis}}\right)\Delta\ \perp\ \mu_{biyt}^{\mathrm{st,min}}\geq 0 \quad (13i)$$
$$\sum_{t'=1}^{t}\left(q_{biyt'}^{\mathrm{ch}}-q_{biyt'}^{\mathrm{dis}}\right)\Delta\leq A_{bi}^{\mathrm{st}}Q_{biy}^{\mathrm{st^v}}(.)\ \perp\ \mu_{biyt}^{\mathrm{st,max}}\geq 0 \quad (13j)$$
$$q_{biyt}^{\mathrm{dis}}q_{biyt}^{\mathrm{ch}}=0 \quad (13k)$$

3.1.4 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 ($t\in\{1,...,N_T\}$; $y\in\{1,...,N_Y\}$; $k,k'\in\{i,j\}$):

$$\Delta l\frac{P_{kyt}(.)+(1-\gamma_{kk'}^{\mathrm{tr}})\left(-\beta_{kyt}q_{kk'yt}^{\mathrm{tr}}\right)}{(1+r)^y}+\mu_{kk'yt}^{\mathrm{tr}}+\mu_{k'kyt}^{\mathrm{tr}}$$
$$-\mu_{kk'yt}^{\mathrm{tr,cap}}\leq 0\ \perp\ q_{kk'yt}^{\mathrm{tr}}\geq 0 \quad (14a)$$

$$\frac{-Inv_{kk'y}^{\mathrm{tr}}}{(1+r)^y}+\sum_t A_{kk'}^{\mathrm{tr}}\sum_{y'=y}^{\min(N_Y,y+PL_{kk'}^{\mathrm{tr}}-1)}\mu_{kk'y't}^{\mathrm{tr,cap}}\leq 0\perp Q_{kk'y}^{\mathrm{tr,new}}\geq 0 \quad (14b)$$

$$q_{kk'yt}^{\mathrm{tr}}=-q_{k'kyt}^{\mathrm{tr}} \quad (14c)$$
$$q_{kk'yt}^{\mathrm{tr}}\leq A_{kk'}^{\mathrm{tr}}Q_{kk'y}^{\mathrm{tr}}(.)\ \perp\ \mu_{kk'yt}^{\mathrm{tr,cap}}\geq 0 \quad (14d)$$

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 [32] 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.

3.2 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 2.3, as following:

$$\max_{\substack{\{q_{miyt}^{\mathrm{ig}},q_{niyt}^{\mathrm{dg}},q_{ijyt}^{\mathrm{tr}},q_{biyt}^{\mathrm{dis}},q_{biyt}^{\mathrm{ch}}\}\succeq 0,\\ \{q_{biyt}^{\mathrm{st}}\},\\ \left\{Q_{miy}^{\mathrm{ig,new}},Q_{niy}^{\mathrm{dg,new}},Q_{ijy}^{\mathrm{tr,new}},Q_{biy}^{\mathrm{st^f,new}},Q_{biy}^{\mathrm{st^v,new}}\right\}\succeq 0}}\sum_{i,y,t}\frac{\Delta\ell}{(1+r)^y}\Bigg\{$$
$$\left(\alpha_{iyt}-\frac{\beta_{iyt}}{2}D_{iyt}(.)\right)D_{iyt}(.)-\sum_m(1-\gamma_{mi}^{\mathrm{ig}})\frac{\beta_{iyt}q_{miyt}^{\mathrm{ig}}{}^2}{2}$$
$$-\sum_n(1-\gamma_{ni}^{\mathrm{dg}})\frac{\beta_{iyt}q_{niyt}^{\mathrm{dg}}{}^2}{2}-\sum_b(1-\gamma_{bi}^{\mathrm{st}})\frac{\beta_{iyt}q_{biyt}^{\mathrm{st}}{}^2}{2}-$$
$$\sum_j(1-\gamma_{ij}^{\mathrm{tr}})\frac{\beta_{iyt}q_{ijyt}^{\mathrm{tr}}{}^2}{2}-\sum_m c_{mi}^{\mathrm{ig}}q_{miyt}^{\mathrm{ig}}-\sum_n c_{ni}^{\mathrm{dg}}q_{niyt}^{\mathrm{dg}}\Bigg\}-$$
$$\sum_{i,y}\frac{1}{(1+r)^y}\Bigg\{\sum_m Inv_{miy}^{\mathrm{ig}}Q_{miy}^{\mathrm{ig,new}}+\sum_n Inv_{niy}^{\mathrm{dg}}Q_{niy}^{\mathrm{dg,new}}$$
$$+\sum_b Inv_{biy}^{\mathrm{st^v}}Q_{biy}^{\mathrm{st^v,new}}+Inv_{biy}^{\mathrm{st^f}}Q_{biy}^{\mathrm{st^f,new}}+\sum_j Inv_{ijy}^{\mathrm{tr}}Q_{ijy}^{\mathrm{tr,new}}\Bigg\} \quad (15a)$$

s.t.

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

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.

To match the KKT conditions of the developed centralized optimization problem with 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,

$$\frac{\sum_{i,t}\sum_{n\in\mathcal{N}_i^{\mathrm{dg}}}q_{niyt}^{\mathrm{dg}}EF_{ni}}{\sum_{i,t}\sum_{n\in\mathcal{N}_i^{\mathrm{dg}}}q_{niyt}^{\mathrm{dg}}+\sum_{m\in\mathcal{N}_i^{\mathrm{ig}}}q_{miyt}^{\mathrm{ig}}}\leq\left(1-\alpha_y^{\mathrm{ER}}\right)EI_{Y_0}^{\mathrm{CO_2}}\perp\mu_y^{\mathrm{ER}}\geq 0,$$

$$\sum_t\left(\sum_{n\in\mathcal{N}_i^{\mathrm{dg}}}\alpha_{ni}^{\mathrm{dg,FR}}q_{niyt}^{\mathrm{dg}}+\sum_{b\in\mathcal{N}_i^{\mathrm{st}}}\alpha_{bi}^{\mathrm{st,FR}}q_{biyt}^{\mathrm{dis}}\right)\geq\alpha^{\mathrm{FR}}\sum_t$$

$$\sum_{m\in\mathcal{N}_i^{\mathrm{ig}}} q_{miyt}^{\mathrm{ig}} \perp \mu_{iy}^{\mathrm{FR}} \geq 0,$$

we need to make the following updates:
(i) equation (11a) must be updated as:

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

(ii) equation (12a) must be updated as:

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

(iii) equation (13b) must be updated as:

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

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

3.3 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:

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

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

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,

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

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

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

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.

4 Case Study and Simulation Results

In this section, we apply our tax and subsidy design 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 hourly (load time) operation of the system during each investment period. The coefficients α and β in (5) are calibrated based on the 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, solar 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 [33], 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 [34], 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 [20], [24]. Note that we can increase the system reliability by increasing the parameter α^{FR}.

4.1 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 subsidy. 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.

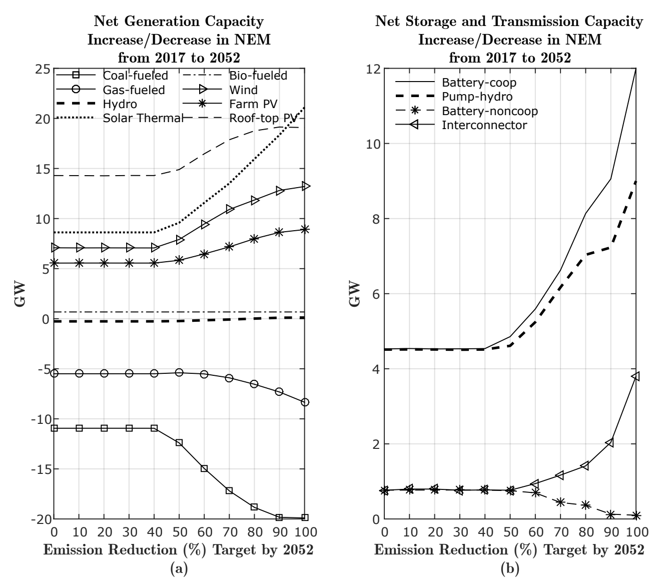

Fig. 1: Net increase/decrease of capacity for (a) generation and (b) storage and transmission technologies by 2052 in NEM for different target levels of emission intensity reduction.

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 Australia until 2050 and 2070 are discussed in [33]). 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.

4.2 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 resource inadequacy and 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. 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 gross demand levels in NEM by 2052 with and without implementing the emission reduction policy. Note that the gross demand includes the roof-top PV generation in addition to the wholesale demand. The divergence of the gross 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.

4.3 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 at each

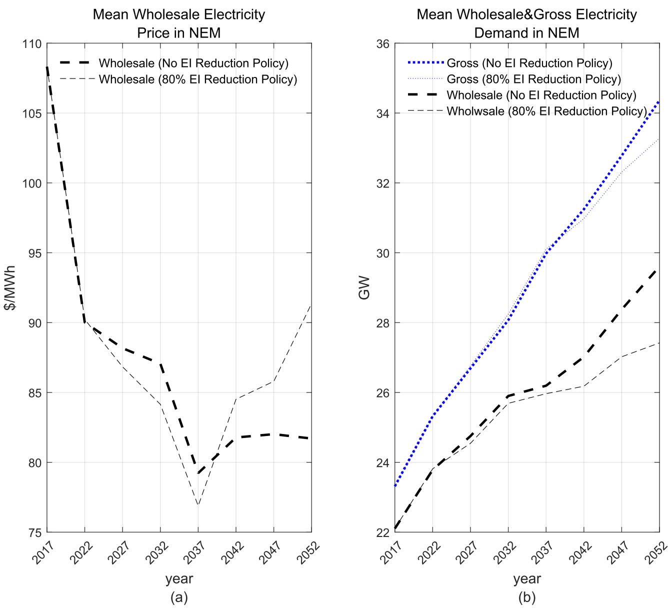

Fig. 2: The average yearly (a) wholesale prices and (b) net and wholesale demands in NEM, without or with emission reduction policy (net demand =wholesale demand + rooftop PV).

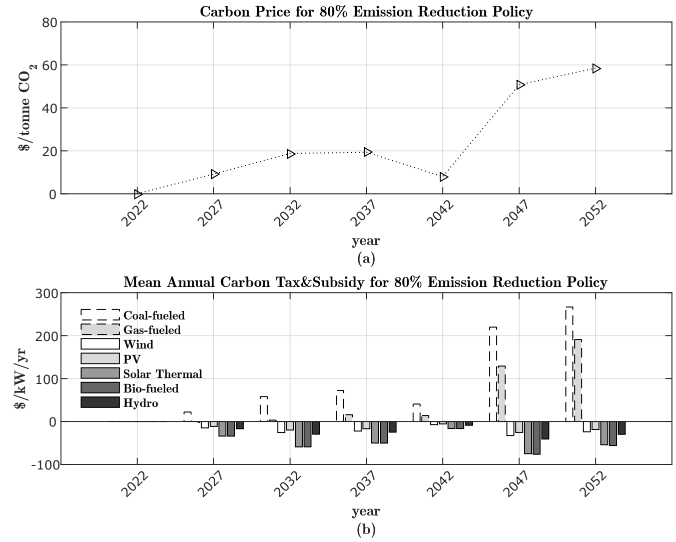

Fig. 3: The trajectory of (a) carbon price, (b) carbon tax (positive) and subsidy (negative) of different generation types during 2017-2052.

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.

4.4 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 increase of batteries' volume capacities because of the decline in their investment cost. The subsidy on hydro and gas-fueled plants also increases over time, which is higher for the gas generators due to their higher capability of fast response provision in the network.

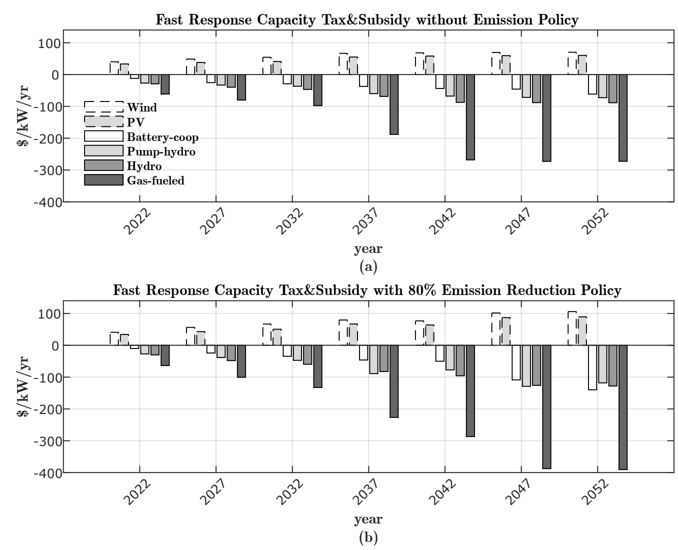

Fig. 4: The trajectory of fast response capacity tax (positive) and subsidy (negative) for (a) No Emission Reduction policy, (b) 80% Emission Intensity Reduction policy.

5 Conclusion

In this paper, we developed a tax/subsidy design framework to calculate model-based quantities of incentives to reach emission and reliability targets in competitive electricity markets. Our market model consists of competitive players who decide on their long-term capacity and generation while they consider the tax/subsidy incentives as penalty/reward for their generation. Our main findings based on our numerical results can be summarized as:

- Although it is commonly accepted that tax on emission and subsidy on fast response capacities could help to reduce emission and improve reliability in the market, our tax/subsidy design framework concisely quantifies the amounts of those incentives required to reach policy makers' emission reduction and market reliability goals while the competitive behaviour of market players is taken into account.
- Considering the competitive behaviour of market players, our tax/subsidy design framework is developed as a game model. We found the NE of the game without the cumbersome conventional method of concurrently solving the KKT conditions of all players, as in [25], [26]. Alternatively, we develop and solve an equivalent centralized optimization problem to find the solution of the game, which reduces the number of variables and constraints in our problem almost by 80%, and the computation time by 90% (Details are given in Appendix B).
- Our numerical results show that taxing emission does 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, up to 4.5%, 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 [24].
- Our results indicate the necessity of designing dynamic emission policies in electricity markets. It is observed in our simulations that the retirement of the aging coal-fueled and gas-fueled generators reduces the designed carbon prices and subsequently the emission incentive policy levels by 50% in 2042 compare to 2039. Thereafter, carbon price levels must rise again to continue the emission intensity reduction trend in the market.
- High penetration of intermittent renewables and gradual retirement of aging gas-fueled plants endangers the system reliability and makes the price highly volatile in the market. The incentive policies of fast response capacity, which penalize the intermittent generators and subsidize the fast response capacities, can lead to higher reliability levels in the network and reduce the price volatility.
- Although the emission and fast response policies considered in our model are based on the policies suggested in [24] 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).

In our future work, we intend to design incentive policies on system strength and inertia as well. 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 [35].

Appendix A
Technology Characteristics

In this section, all financial and technical information on intermittent and dispatchable generators, storage technologies and interconnectors are from [20], [33], [36].

TABLE 1: 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
$\tilde{Inv}^{\mathrm{ig}}$ ($\frac{\$}{\mathrm{kW}}$) $^{(a),(b)}$	$2400^{(1.5\%)}$	$2190^{(3.5\%)}$	$2100^{(3.5\%)}$
c^{ig} ($\frac{\$}{\mathrm{MWh}}$)	5	2	3
PL^{ig} (yr)	25	20	20
$\bar{C}^{\mathrm{ig}}$ (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 3: 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
$\tilde{Inv}^{\mathrm{st,f}}$ ($\frac{\$}{\mathrm{kW}}$)$^{(a)}$	$800^{(0.5\%)}$	$225^{(3.1\%)}$	$150^{(3.1\%)}$
$\tilde{Inv}^{\mathrm{st,v}}$ ($\frac{\$}{\mathrm{kWh}}$)	$70^{(0.5\%)}$	$225^{(3.1\%)}$	$225^{(3.1\%)}$
$PL^{\mathrm{st,f}}$ (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 2: Financial and Technical Information on Dispatchable Generators in NEM.

Plant:	Q^{dg}_{2017} (GW)	$\tilde{Inv}^{\mathrm{dg}}$ $(\frac{\$}{\mathrm{kW}})^{(\mathrm{a})}$	c^{dg} $(\frac{\$}{\mathrm{MWh}})$ operation+fuel	PL^{dg} (yr)	R^{up}, R^{dn} $(\frac{\%}{\mathrm{hr}}, \frac{\%}{\mathrm{hr}})$	A^{dg} (%)	EF $(\frac{\mathrm{t_{CO_2}}}{\mathrm{MWh}})$	RA^{dg} $(\frac{\mathrm{TWh}}{\mathrm{yr}})$	$\alpha^{\mathrm{dg,FR}} \in \{0,1\}$
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

$^{(\mathrm{a})}$ Capital cost de-escalator rate (%). After 2037 the de-escalator used for solar thermal drops to 0.3%.

TABLE 4: 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

Appendix B
Modeling Platform

We developed our models in GAMS software and used CPLEX [37] and PATH [38] solvers to find the solutions in the centralized problem and the original game, respectively. The number of equations in the centralized optimization problem is almost 80% less than the number of KKT equations of the game, i.e., 2310042 compare to 10710126, which reduces the computation time almost by 90%, i.e., from 38102 s to 4191 s, on a computer with Core i7, RAM 16 GB.

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