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Qingyu Xu, Benjamin F. Hobbs

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With both a simple schematic model and a detailed WECC generation-transmission expansion planning model for the year 2034 called JHSMINE, we examine the following deemed emission rate schemes for estimating and charging for emissions associated with electricity imports: no BCA, facility (import source)-specific deemed rate, a facility-neutral and constant deemed rate, and a facility-neutral and dynamic deemed rate. Our results suggest that, compared with cases with either no BCA or a BCA using facility-based deemed emission rates, facility-neutral schemes can provide efficiency gains by simultaneously lowering WECC-wide emissions and costs without raising payments by California consumers. Emissions leakage declines greatly. The precise value of the deemed rate affects these gains. One particular facility-neutral dynamic scheme in which rates are set by marginal emission rates external to California provides the greatest gain in economic efficiency. Our results also show the impact of carbon pricing and BCAs on transmission investment economics: California's unilateral AB32 carbon pricing encourages more interstate transmission expansion because power imports are more profitable; however, BCAs that are cost-effective in lowering total regional emissions will dampen those incentives.

Keywords Carbon policy, Border carbon adjustment, Electricity markets, Expansion planning, Market efficiency

JEL Classification H23 (Pollution Tax) L94 (electricity industry) Q48 (energy policy)

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Economic Efficiency of Alternative Border Carbon Adjustment Schemes:
A Case Study of California Carbon Pricing and the Western North American Power Market

Qingyu Xu[a], Benjamin F. Hobbs[a,*]

[a] Whiting School of Engineering, Johns Hopkins University, N. Charles St, Baltimore, MD 21218
[*] Corresponding Author: bhobbs@jhu.edu

Abstract. A local jurisdiction that regulates power plant emissions, but participates in a larger regional power market faces the issue of emissions leakage, in which local emissions decrease, but emissions associated with the imported power increase. Border carbon adjustment (BCA) schemes can be imposed on imports in an attempt to lessen leakage. This paper explores the potential cost and emission impacts of alternative BCA policies that could be implemented in the California AB32 carbon pricing system. We focus on cost and emission impacts on the power sector in California and the rest of the Western Electricity Coordinating Council (WECC) region, the latter of which provides approximately 23.5% of California's electricity requirements. With both a simple schematic model and a detailed WECC generation-transmission expansion planning model for the year 2034 called JHSMINE, we examine the following deemed emission rate schemes for estimating and charging for emissions associated with electricity imports: no BCA, facility (import source)-specific deemed rate, a facility-neutral and constant deemed rate, and a facility-neutral and dynamic deemed rate. Our results suggest that, compared with cases with either no BCA or a BCA using facility-based deemed emission rates, facility-neutral schemes can provide efficiency gains by simultaneously lowering WECC-wide emissions and costs without raising payments by California consumers. Emissions leakage declines greatly. The precise value of the deemed rate affects these gains. One particular facility-neutral dynamic scheme in which rates are set by marginal emission rates external to California provides the greatest gain in economic efficiency. Our results also show the impact of carbon pricing and BCAs on transmission investment economics: California's unilateral AB32 carbon pricing encourages more interstate transmission expansion because power imports are more profitable; however, BCAs that are cost-effective in lowering total regional emissions will dampen those incentives.

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1 Introduction

All carbon pricing policies are limited in geographical and/or sector coverage (World Bank, 2017). Furthermore, limited geographical coverage can induce so-called carbon leakage, i.e., increased emissions in non-regulated jurisdictions or sectors, because their production will become more competitive than production in the regulated jurisdiction (IPCC, 2014). Leakage therefore diminishes the effectiveness of local regulation. Consequently, in the case of imports from unregulated regions, this issue has led to proposals for border cost adjustment (BCA) schemes in which imports and exports of commodities between regulated and external jurisdictions are regulated, subsidized, and/or taxed (e.g., border tax adjustment) (Böhringer et al., 2012; Fischer and Fox, 2012; Ismer and Neuhoff, 2007).[1] Intuitively, regulations/subsidies/taxes can be imposed upon inter-state transactions, the most basic form of interaction. BCA on import transactions typically requires the buyer or the seller to pay a carbon tax or surrender carbon emission allowances at an assumed emission rate for the commodity, perhaps differentiated by the source or other attributes.[2]A key decision for policymakers is thus how to set emission rates for imports, also called deemed emission rates (or default emission rates). In this paper, we use the terms deemed and default emission rates interchangeably, denoting them both as DR.

However, because of the homogeneity of electricity and the inability to unambiguously trace power from source to user,[3] when the DR is set on the basis of assumptions about which power plants in the non-regulated region are the sources of imports, there is a strong incentive for non-regulated power plants to rearrange contracts among themselves. This rearrangement, called shuffling, results in those imports being assigned to relatively low-emission facilities, while assigning high-emission plant output to users in the non-regulated region, thus apparently reducing emissions associated with imports without actually changing the physical dispatch. Consequently, a large portion of emission reductions occurs only on paper. This contract (or resource) shuffling has been widely recognized by academia (Bushnell et al., 2014; Chen et al., 2011; Ismer and Neuhoff, 2007) and policymakers (CAISO, 2018).

[1] In this work, we emphasis importing jurisdictions, where most of the debate about BCA has focused.

[2] BCA regulation can also specify whether to rebate for the export carbon taxes paid on transactions or otherwise provide an exemption from paying for emissions (Fischer and Fox, 2012; PJM, 2020).

[3] I.e., electricity end-users cannot easily distinguish where or how their electricity is produced in interconnected power systems.

An alternative DR scheme that eliminates the incentive for shuffling applies the same DR to all imports. However, there remains the question of the best level for the DR, and whether it should vary over time. To policymakers in the regulated jurisdiction, an efficient DR scheme would reduce leakage and total regional emissions at minimum cost. In this paper, we consider the definition of a Pareto set of DRs that are efficient in terms of cost (either regional or California-only) and total regional emissions, while identifying inefficient DRs which would have either higher cost or higher emission, or both, than some point in the Pareto set. To define the Pareto set, we consider simple DR schemes imposing the same DR for any imports at any time (constant and facility-neutral), and more complicated schemes, including static but facility-based schemes, facility-neutral but dynamic schemes.

California's carbon pricing currently uses facility-based (or sometimes source-region-based) DR for estimating import emissions. That is, California cap-and-trade system requires electricity importers to specify the source of electricity contracts and to surrender allowances on the basis of the emissions rate of that supply (CARB, 2014). If no particular source is specified, a generic allowance surrender rate of 0.428 tons/MWh is imposed. Several alternative approaches exist to dynamically calculate the DR (or determine who is truly responsible for the imports), by using near-term or real-time system operation information. For instance, the California Independent System Operator (CAISO) had proposed a so-called two-stage framework to calculate the real-time composition of California net imports (CAISO, 2017). Although this proposal was not ultimately implemented, it highlights the possibility of using real-time information to identify which external plans truly support the demand for imports and then setting the DR accordingly.

Use of dynamic marginal emission rates calculated on a system basis has also been proposed for BCA schemes. Such analyses underlay studies of pass-through of carbon costs to electricity prices (Kim et al., 2010; Sijm et al., 2012). Because electricity prices will increase due to the imposed carbon cost (pass-through), an effective carbon tax per unit of electricity can be calculated based on the emissions of the marginal unit in the regulated market times the carbon price. Using marginal pricing principles, a system operator can calculate the rise in electricity price because of carbon pricing within the regulated market and, on the basis of this increase in price, artificially lower the electricity price paid to imports from external generators. This can be viewed as being equivalent to a BCA in which the DR is based on marginal internal (regulated market) emissions. Such an approach has been proposed in the carbon pricing plan of the New York

Independent System Operator (NYISO, 2018). Although New York State is a member of Regional Greenhouse Gas Initiative (RGGI), NYISO proposes adopting a carbon cost of approximately \$50/ton for electricity sold on its market, which is much higher than the current RGGI allowance price of about \$5/ton (RGGI, 2018). To prevent the leakage that such a high price might incent, adoption of a BCA scheme is required; NYISO proposes to use the above method to lower the *ex post* power price for imports by the amount of the CO_2 premium resulting from its carbon pricing (NYISO, 2018).

The marginal emission rate of generators outside of a carbon pricing regime (i.e., the external marginal emission rate) can also be used. Specifically, system-wide marginal emission rates have been estimated for the United Kingdom (UK) in Hawkes (2010), for the U.S. in Siler-Evans et al. (2012), and locally for the Pennsylvania-New Jersey-Maryland interconnection in (PJM, 2019). In short, dynamic DR calculations are possible and are under active consideration for implementation in BCA schemes.

The elements of BCA policy include not only the DR for the cross-border transaction, i.e., whether to discriminate among sources or over time (e.g., day vs. night, or summer vs. winter), but also the direction of BCA (whom to charge/rebate), i.e., whether to charge imports, rebate exports or both (Fischer and Fox, 2012). For example, the PJM interconnection includes both RGGI member and non-member states, and thus is considering BCA options among its subregions to mitigate carbon leakage, either by only imposing emission charges on imports (one-way) or rebating exports as well (two-way); the assumed DRs are facility-based (PJM, 2020). However, in this paper, we emphasize policies involving only charging imports and not giving rebates to exports, consistent with California policy. Our results focus on solving the problem of defining Pareto optimal DRs for imported power, although we do briefly summarize an analysis of a BCA with rebates for exports.

How carbon pricing affects power systems has a long history of research, such as Bushnell et al. (2014); Chen et al. (2011); Hytowitz (2018); Lanz and Rausch (2011); Levin et al. (2019); Palmer et al. (2017). In one example, Chen et al. (2011) and Bushnell et al. (2014) have revealed that a high volume of contract shuffling in the electricity sector would likely accompany high carbon leakage in the California cap-and-trade system. Levin et al. (2019), with a power system expansion planning model, has shown that the adoption of a carbon tax in Texas is a cost-efficient way to reduce emissions, whereas a Renewable Portfolio Standard (RPS) is less effective. Lanz and Rausch (2011) compared the results from top-down and bottom-up modeling approaches applied to a national carbon pricing policy in the United States.

Researchers, however, have yet to address fine tuning of BCA strategies and identification of Pareto optimal deemed emission rates for imports. Our goal is to address this general question in the context of the first state-level carbon trading program in the US, California's AB32. Here, we use a bottom-up approach to capture the diversity of generation technologies, transmission limitations, and the geographical distribution of fuels and demands that are critical to determining the impact of carbon regulation on trade patterns, costs, and prices within the power sector. We model the investment decisions of power generation, the hourly dispatch of generation and transmission, and the bilateral trading of the energy credit in a single optimization, which in turn is equivalent to a long-run power market equilibrium. Similar modeling approaches have been used in Bushnell et al. (2014); Lanz and Rausch (2011); Levin et al. (2019); Özdemir et al. (2020); Palmer et al. (2017). Other electricity analyses have been more aggregate (Chen et al., 2011) or have considered just short-run operational (dispatch) effects (Hytowitz, 2018; PJM, 2020). For analyses that have used complementarity problem representations rather than a cost minimization approach to calculate partial equilibria in a power market, see, e.g., Chen et al. (2011); Zhao et al. (2010). Our work here differs from previous studies in two ways:

1) We provide detailed engineering-economic modeling of generation and transmission expansion in response to carbon pricing policies, whereas most previous studies do not consider transmission investment. Transmission congestion significantly impacts operations and emissions in the WECC system; and we therefore conjecture that the economics of new transmission could be significantly affected by carbon policy, while transmission investment could alter the impacts of carbon policy.
2) We provide detailed modeling of credit trading for renewable portfolio standards as well as its interaction with trade, leakage, contract shuffling, and BCA issues, and their joint effects on power sector investment. In contrast, previous studies have either focused on carbon pricing rather and not BCA design, e.g., Chen et al. (2011), or disregarded interstate/inter-jurisdictional interactions altogether, e.g., Levin et al. (2019).

In this paper, we analyze the potential economic efficiency gains and impacts of different DR settings. More specifically, we ask the following two questions: (1) For a unilateral carbon pricing jurisdiction in an interconnected electricity market, how will BCA schemes affect overall emission reductions, emission leakage, regional electricity production, transmission expansion, and consumer payments? (2) Given the current California AB32 cap-and-trade system, if we define a "better" DR scheme as providing Pareto improvements (i.e., lower overall emissions and higher market efficiency), do such schemes exist, and how large might their benefits be in the year 2034 under one set of assumptions?

We do not claim that these results are a definitive assessment of the benefits of alternative BCA approaches for California, but rather they provide some basic insights about the relationship of deemed rates to leakage and cost-effective emissions reductions that may be also be applicable elsewhere. Before presenting our long-run equilibrium model and the results of its application (Sections 3 and 4, respectively), we provide a simple two-region example that illustrates some general conclusions concerning the efficiency of deemed rates in BCA schemes; the California application then quantifies the magnitude of the benefits and costs of alternative DRs in a realistic context.

2 Illustrative Two-Node Example

In this section, we use a simple two-node example to illustrate several essential concepts and qualitative results if carbon pricing (with or without BCA) is implemented in a power-importing state, such as California.

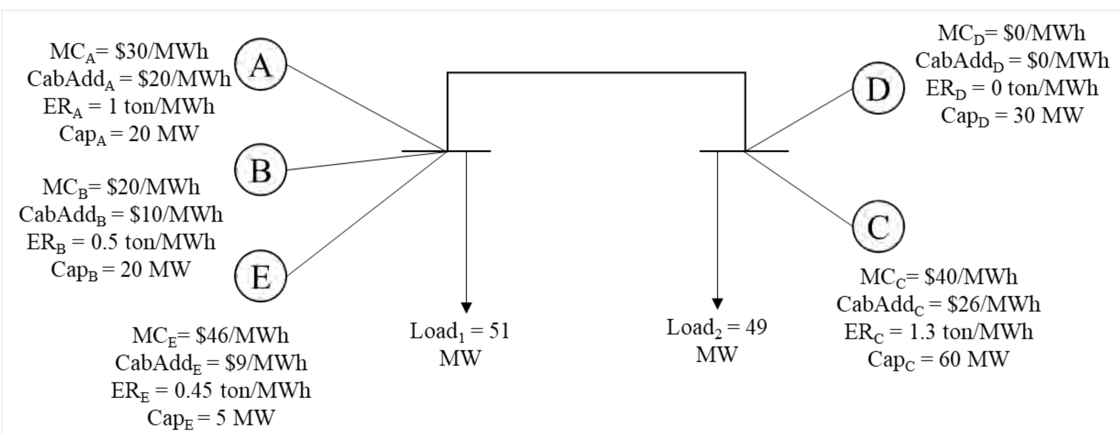

Fig. 1. The two-node example.

The two-node example is a single-hour economic dispatch without transmission limits. Five generators (A to E), each with a different marginal cost, emission rate, and capacity, are dispatched to meet the electricity demand at two nodes (Nodes 1 and 2). The data are shown in Fig. 1. Generator D is emission-free, and E is a low-emission generator with a high marginal cost.

If a carbon price of \$20/ton is applied at Node 1, part of it will be passed through, resulting in higher power prices.

This example demonstrates four cases:

- No carbon price;
- Node 1 with a carbon price at \$20/ton;
- On top of the \$20/ton carbon price, Node 1 charges imports using a facility-based DR; and
- On top of the \$20/ton carbon price, Node 1 charges imports by using a DR of 1.3 tons/MWh, which is the same as the emission rate of generator C.

The solutions are compared in terms of resource cost, defined as the total operation cost, excluding the price of carbon. A relative accounting carbon leakage metric is defined as the relative difference between the "system-wide emission reduction" and "regulated emission reduction," with the latter calculated as the local emissions plus the imported deemed emissions (Chen et al., 2011; Ruth et al., 2008). Let the system-wide emissions reduction, local emissions reduction, rest of system emissions reduction, and accounted imported emissions reduction be defined as S, L, R, and I, respectively. Then the reduction in regulated emissions is (L+I), and S = L + R. The relative accounting leakage = 100% - S/(L+I) = 100% - (L+R)/(L+I), which can be interpreted as the portion of claimed reductions that do not really occur when the entire system is considered. We note that the accounting leakage is non-zero if and only if $I \neq R$; i.e., the leakage is non-zero if the accounted imported emission reduction is a biased estimate of the rest of the system emission reduction. When the BCA uses contract sources' emission rate for imported emission calculation, such a bias is introduced by the contract shuffling between existing/new emitting contracts and power contracts from less-emitting plants. If instead, a DR scheme applies the same deemed rate to all contract sources, then shuffling incentives are removed. In that case, it is the inaccuracy of the DR that can introduce bias.

There is second, and distinct, type of leakage that is frequently used in policy analyses, which we call the "physical leakage." This physical leakage can be calculated as 100%×(-R/L), which reflects the portion of physical internal emissions reductions that are offset by increased emissions outside the region. In this paper, the term “carbon leakage” will refer to the accounting carbon leakage unless stated otherwise.

The evaluation of imported emissions, the core of this paper, depends on the choice of BCA scheme and DR. Consequently, even before implementing carbon prices, the imported and regulated emissions can differ among various BCA schemes.

Table 1. Results of the Two-node Example

	No Carbon Price		Carbon Price at $20/ton at Node 1					
			No BCA		Facility-based		Deemed rate at 1.3 tons/MWh	
Sales from Plant to Node:	1	2	1	2	1	2	1	2
A (sited at Node 1)	20	0	0	0	1	0	20	0
B (sited at Node 1)	20	0	0	20	20	0	20	0
C (sited at Node 2)	0	30	21	29	0	49	0	25
D (sited at Node 2)	11	19	30	0	30	0	6	24
E (sited at Node 1)	0	0	0	0	0	0	5	0
Emissions at Node 1	30		10		11		32.25	
Deemed Emissions Imported by Node 1 (tons)	0, 0, 11×1.3 =14.3 (depends on BCA)		0 (no BCA)		0 (all imports are from Gen D)		6×1.3 = 7.8	
Regulated Emissions (tons)	30, 30, 44.3		10		11		40.05	
Regulated Emission Reduction (RER, tons)	-		20		19		4.25	
Resource Cost ($)	2200		2400		2390		2230	
Total Emission (tons)	69		75		74.70		64.75	
System Emission Reduction (SER, tons)	-		-6		-5.7		4.25	
Accounting Leakage (=100% - SER/RER)	-		130%		130%		0%	
Powerflow from Node 2 to Node 1	11		31		30		6	

The results of the four cases are shown in Table 1. If there is no carbon price, the dispatch follows the merit order formed by plant marginal fuel costs. Consequently, generator C will be the marginal unit, and generators A, B, and D will be operated at their maximum capacity. Multiple feasible contract arrangements exist, and Table 1 shows one in which the power imports (to Node 1) are entirely from the emission-free generator D.

Carbon leakage occurs if a carbon price of $20/ton is implemented at Node 1. Because of the carbon price, generation at Node 1 will become expensive. For example, generator A's marginal cost will increase to $50/MWh and will then exceed generator C's. Consequently, the dispatch changes from the no-carbon-price case, and, in at least some cases, Node 1 increases its imports.

With that carbon price at Node 1, Table 1 shows that, without BCA, no power would be generated from A, while C would be dispatched up to fill the gap, with Node 1's net imports increasing from 11 MW to 31 MW. Without A's generation, the local emissions at Node 1 would decrease by 20 tons; however, the system-wide emission would increase by 6 tons because of the incremental generation from C, which has a high emissions rate. Because there is no BCA, the regulated emissions are by definition the same as the local emissions and also decrease by 20 tons. The leakage (a net of 26 tons) is large because the real reduction in total regional emissions of -6 tons (in fact, this is an increase in emissions) is much lower than the amount seen by Node 1's regulators (20 tons), thus resulting in a leakage of 100% - (-6/20) = 130%.

If Node 1's regulators instead implement both the $20/ton tax and a BCA that charges electricity imports according to the emission rate of the source facility (hereafter the facility-based DR), the imports will be as clean as possible. As shown in Table 1, the least expensive dispatch and contract arrangement for Node 1 is to import power from generator D as much as possible, who then sells to consumers at Node 1 rather than Node 2. However, this is contract shuffling that results in no change in D's operation. It is instead C that actually increases its output, just as in the no BCA case, but the facility-based BCA system completely fails to detect C's incremental emissions. From the perspective of Node 1's regulators, the imports now appear to be emission-free, and the regulated emissions decrease from 30 to 11 tons. The system emissions, however, increase by 5.7 tons above the no carbon price case. This is also a leakage of 100% - (-5.7/19) = 130%. Notably, the facility-based BCA slightly mitigates the system-wide emissions while lowering the resource cost relative to that of the no BCA case (0.3 tons and $10), but this Pareto efficiency gain is very limited.

On the other hand, if the regulator at Node 1 instead implements a BCA that deems imports from Node 2 as emitting 1.3 tons/MWh, the system will be much cleaner. Because the emission regulator charges all imports a carbon price of 1.3×20 = $26/MWh, the imports (and the powerflow) greatly decrease. Node 1 is incentivized to dispatch its own fleet and then to rely on imports from generator C. Node 1's local emissions increase, but the system-wide emissions decrease by 4.25 tons relative to the no regulation case. More importantly, because the imports decrease, the imported emissions also decrease. In the no carbon price cases, if the imports are evaluated at an emission rate of 1.3 tons/MWh, the imported emissions are 14.3 tons.[4] The regulated emissions (as if a DR of 1.3 tons/MWh were implemented) then decrease from (30 + 14.3) = 44.3 tons to (32.25 + 7.8) = 40.05 tons, or 4.25 tons. Because this reduction happens to be the same as the system-wise emission reduction, the relative leakage is coincidently zero (0%). Such a DR at 1.3 tons/MWh not only provides more emission reductions but also lowers resource costs more than both the no BCA case and the facility-based BCA case, thus greatly improving economic efficiency. On the other hand, if the DR is set to 0.45 tons/MWh, the solution will be the same as that of the no BCA case; this shows that the precise level of the DR can matter greatly.

Finally, because each of the four cases introduces a different power flow pattern (last row of Table 1), the carbon pricing and BCA should strongly affect the value of the transmission. For example, compared with the no carbon price case, a carbon price at \$20/MWh without BCA increases the powerflow from 11 MW to 31 MW. If there is a transmission limit at 15 MW, and an upgrade can release the limit, such a transmission upgrade would be valuable. However, if Node 1 was to implement a 1.3 tons/MWh DR, such an upgrade would have no value at all. In conclusion, local carbon pricing in power importing jurisdictions can encourage transmission investment because of the artificial increase in the market value of imports, while an effective BCA may discourage transmission investments.

This simple two-node example shows that (1) implementing unilateral local carbon pricing will introduce carbon leakage in power systems, thus potentially causing total regional emissions to shrink less than local emissions, or even increase; (2) BCA that uses facility-based DR can be ineffective in reducing carbon leakage; (3) a high enough DR scheme that is indifferent to import sources can mitigate leakage by eliminating incentives to shuffle contracts and thus improve economic efficiency; and, finally, (4) unilateral carbon pricing and various BCA schemes can affect power flow patterns and the consequent value of transmission reinforcements. Our task is now to quantify the impact and to test whether these observations still hold in a realistic system, as described in the remainder of this paper.

[4] Again, there are multiple contract arrangements because of the homogeneity of electricity, and the 11 MW import happens to have the least amount of emissions, as evaluated with both facility-based BCA and BCA with a facility-neutral emission rate.

3 Methodology

3.1 General overview

The general approach of this work is to first formulate a long-run (investment and operations) partial equilibrium problem for a single year (2034) for a competitive multi-jurisdictional electricity market with transmission constraints and different carbon and RPS rules in each jurisdiction or subset of jurisdictions. We show that a single optimization model exists whose solution satisfies those equilibrium conditions. If the solution exists, then the optimization model can be used to simulate the market and show the impact of alternative formulations of carbon border tax rules. This general approach is widely used in energy market modeling (Gabriel et al., 2013) and in environmental regulation in the power sector; an example is demonstrated by Chen et al. (2011). The single optimization is in the form of a static (single-year) coordinated transmission-generation expansion planning, an enhanced version of Johns Hopkins Stochastic Multistage Integrated Network Expansion tool based on Xu and Hobbs (2019).

The core of this formulation involves modeling the non-electrical attributes of power generation, which broadly include but are not limited to the time of generation, source, sink, renewable credits, and emissions. The value/cost of these attributes can be artificially created by regulations such as RPS and carbon pricing. We model these attributes with one single variable, contract power flow ($cpf_{w,h,k}$), and thus we implicitly assume that these attributes are bundled. The definition of this variable is "the MW attributes sold from GenCO k at hour h to LSE w"; effectively, it is a bilateral contract for energy credits. For instance, if 60% of California's electricity demand must be supported by contracts from renewable resources, no more than 40% must be from non-renewable sources; consequently, California LSEs must buy non-renewable credits to support such a composition (possibly at zero price). That is, the contract power flow that we defined is a generalization of the renewable energy credit of RPS and the emission allowances of carbon pricing, and can encompass both. The model can be easily modified to consider the emission allowance and renewable credit as unbundled by defining two variables, and we will consider the impact of bundling as a direction for future research.

With the above framework of tracking non-electrical attributes of power generation established, the BCA mechanism can be readily modeled. We start the model presentation by defining the nomenclature of the problem and then listing the optimization problems of different market players, including the ISO, Generation Companies (GenCOs), and Load Serving Entities

(LSEs). Finally, we end this section by documenting the equivalent single optimization in the form of coordinated transmission-generation expansion planning.

3.2 Nomenclature

3.2.1 Sets and Indices

H	Hours, index h
I	Buses, index i
K	Generators, index k
i_k	Bus i where generator k is located
K_i	Generators connected to bus i
K_w	Generators belonging to state w
L	Transmission lines, index l
W	States/provinces, index w (note that more generally, other geographic divisions can be used, and multiple LSEs can serve an individual division).
Y	Years, index y
w_k	Index: state w that financially owns generator k; also called the home state of generator k

3.2.2 Parameters

AER_h	Average emission rate at hour h, additional super/subscripts will apply depending on the context, units: tons/MWh
$CTAX_w$	Carbon price or tax of state w, units: \$/ton
$DR_{w,h,k}$	Deemed emission rate assumed for the energy credit contract between the state-level LSE w and generator k at hour h, units: tons/MWh
$GCOMI_k$	Initial generator commission status of generator k, 0–1, unitless; 1 if the total available capacity is fully in commission.
GER_k	Emission rate of generator k, units: MW
$GEXCA_k$	Annualized generation expansion cost, units: \$/year
$GFOM_k$	Fixed operating and maintenance cost of generator k, units: \$/MW-year
$GHAV_{k,h}$	Hourly availability of generator k, unitless
$GVC_{h,k}$	Variable cost of generator k, including fuel cost and variable O&M cost, units: \$/MWh

$HW_{y,h}$	# of hours represented by hour h in year y, units: hour
$IRPS_w$	In-state renewable portfolio standard (RPS) of state w, unitless (fraction of demand)
$LBI_{l,i}$	Line-bus incidence matrix: 1 if bus i is the to-bus of line l; -1 if bus i is the from-bus of line l; 0 otherwise, unitless
$LCOMI_l$	Initial commission status of transmission line l, 0–1, unitless
$LEXCA_l$	Annualized transmission expansion cost for transmission line l, units: \$/year
LTM_l	Line rating (or the thermal limit) of transmission line l, units: MW
MER_h	Marginal emission rate at hour h, additional super/subscripts will apply depending on the context, units: tons/MWh
$RE_{w,k}$	Renewable eligibility; 1 of generator k is considered renewable in state w, unitless
RPS_w	RPS of state w, unitless
$VOLL$	Value of lost load, units: \$/MWh

3.2.3 Variables

$cpf_{w,h,k}$	Variable: energy credit contract from generator k to state-level LSE w at hour h, units: MW
$cpfb_{w,h,k}$	Variable: energy credit contract purchased by the state-level LSE w from generator k at hour h, units: MW
$cpfs_{w,h,k}$	Variable: energy credit contract sold by generator k to the state-level LSE w at hour h, units: MW
λ	Dual variables: shadow prices of the constraints; the meaning and the units depend on the super/subscripts
$gincexp_k$	Generator incremental expansion, 1 if generator k starts to be commissioned, 0 to 1, unitless
$gincret_{s',y'}$	Generator incremental retirement, 1 if generator k is fully decommissioned from its initial status, 0 to 1, unitless
$gstat_k$	Generator commission status, 1 if generator k is in commission, 0 to 1, unitless
$gopt_{h,k}$	Power output of generator k at hour h, nonnegative, units: MW
$lincexp_l$	Transmission line incremental expansion, 1 if transmission line l becomes commissioned, 0 to 1, unitless
$lstat_l$	Transmission line commission status, 1 if transmission line l is in commission, 0 to 1, unitless

$pf_{h,l}$	Power flow on transmission line l at hour h, unrestricted, units: MW
$nload_{h,i}$	Load shedding at bus i at hour h, nonnegative, units: MWh
$nrps_{h,w}$	Non-compliance with RPS policy, nonnegative, units: MW

3.3 ISO problem

The ISO's objective is to maximize its annualized profit from arbitrage across the nodes of the network and to expand the network, if profitable, by paying the annualized capital cost of the transmission line. Although the ISO is not maximizing the congestion rent in the real word, it is a good approximation because it is equivalent to maximizing the surplus from supply and demand bids (see Hobbs et al. (2000)). The objective is to maximize equation (1), where the variable $\lambda_{h,i}^{LMP}$ is the locational marginal price:

$$\text{Maximize} \quad ISO = \sum_h HW_h \cdot \sum_l \left(\sum_i LBI_{i,l} \cdot \lambda_{h,i}^{LMP} \right) \cdot pf_{h,l} - \sum_l LEXCA_l \cdot lincexp_l \tag{1}$$

Constraints (2) and (3), below, are the upper and lower limits of the power flow imposed by transmission line thermal limits. Although this is a pipes-and-bubbles representation, a linearized DC load flow is possible. Constraint (4) keeps track of the line availability, and Constraint (5), below, is the upper limit of the line availability and the expansion decision.

$$pf_{h,l} - LTM_l \cdot lstat_l \leq 0 \quad (\overline{\lambda}_{h,l}) \quad \forall h,l \tag{2}$$

$$-pf_{h,l} - LTM_l \cdot lstat_l \leq 0 \quad (\underline{\lambda}_{l,h}) \quad \forall h,l \tag{3}$$

$$lstat_l - \left(LCOMI_l + lincexp_l\right) = 0 \quad (\lambda_l^{Te}) \quad \forall l \tag{4}$$

$$\left(lstat_l, lincexp_l\right) - 1 \leq 0 \quad (\lambda_l^{Ts}, \lambda_l^{Tx}) \quad \forall l \tag{5}$$

The optimality conditions, i.e., the Karush–Kuhn–Tucker (KKT) conditions, can be derived as in (6) to (12). Of note, we scale up the hourly constraint by the number of hours HW_h while deriving the optimality conditions in the remainder of this section.

$$pf_{h,l} \ free, \quad \left(\overline{\lambda}_{h,l} - \underline{\lambda}_{h,l}\right) - \sum_i LBI_{i,l} \cdot \lambda_{h,i}^{LMP} = 0 \quad \forall h,l \tag{6}$$

$$0 \leq lstat_l \perp -\sum_h HW_h \cdot LTM_l \cdot \left(\overline{\lambda}_{h,j} + \underline{\lambda}_{h,l}\right) - \lambda_l^{Te} + \lambda_l^{Ts} \geq 0 \quad \forall l \tag{7}$$

$$0 \leq lincexp_l \perp LEXCA_l + \lambda_l^{Tx} + \lambda_l^{Te} \geq 0 \quad \forall l \tag{8}$$

$$0 \leq \overline{\lambda}_{h,l} \perp -pf_{h,l} + LTM_l \cdot lstat_l \geq 0 \quad \forall h,l \tag{9}$$

$$0 \le \lambda_{h,l} \perp pf_{h,l} + LTM_l \, lstat_l \ge 0 \quad \forall h,l \tag{10}$$

$$\lambda_l^{Te} \; free, \quad lstat_l - \left(LCOMI_l + lincexp_l\right) = 0 \quad \forall l \tag{11}$$

$$0 \le \lambda_l^{Ts}, \lambda_l^{Tx} \perp -\left(lstat_l, lincexp_l\right) + 1 \ge 0 \quad \forall l \tag{12}$$

3.4 Generation Companies

Each GenCO *k* attempts to maximize its annualized profit from the energy market, and thus the objective is to maximize Eq. (13) subject to constraints (14) to (17). For simplicity, we omit "for all *k*" from the constraint domain and omit nonnegative constraints as well. The objective function of each GenCo Eq. (13) is the annual net profit, which equals the revenues from both the electricity market and the energy credits market minus the variable cost, carbon allowance cost, and fixed operation and maintenance cost. If profitable, the generation companies will expand the generation fleet by paying the annualized expansion cost; if keeping the plant running is not economical, the generation capacity will be retired.

$$\text{Maxmize } (\forall k) \quad GP_k = \left(\begin{array}{l} \sum_h HW_h \cdot \lambda_{h,i_k}^{LMP} \cdot gopt_{h,k} + \sum_h HW_h \cdot \left(\sum_w \lambda_{w,h,k}^{EC} \cdot cpfs_{w,h,k} \right) \\ -\sum_h HW_h \cdot GVC_{h,k} \cdot gopt_{h,k} - \sum_h HW_h \cdot CTAX_{w_k} \cdot GER_k \cdot gopt_{h,k} \\ -GFOM_k \cdot GNPL_k \cdot gstat_k - GEXCA_k \cdot GNPL_k \cdot gincexp_k \end{array} \right) \tag{13}$$

Constraint (14) is the capacity limit of the generation output for each hour, accounting for both forced outage rates and (in the case of intermittent sources) hydro, wind, or solar availability, and constraint (15) requires generator *k* to sell all the non-electric attributes to the LSEs through energy credit contracts ($cpf_{w,h,k}$). Constraint (16) keeps track of the plant status, i.e., how much of the maximum capacity is available in a given hour. Constraint (17) is the upper limit of the generator availability, expansion decision, and retirement decision.

$$gopt_{h,k} - GNPL_k \cdot GHAV_{h,k} \cdot gstat_k \le 0 \quad (\lambda_{h,k}^{cap}) \quad \forall h \tag{14}$$

$$gopt_{h,k} - \sum_w cpfs_{w,h,k} = 0 \quad \left(\lambda_{h,k}^{Credit}\right) \quad \forall h \tag{15}$$

$$gstat_k - \left(GCOMI_k + gincexp_k - gincret_k\right) = 0 \quad (\lambda_k^{Ge}) \tag{16}$$

$$\left(gstat_k, gincexp_k, gincret_k\right) - 1 \le 0 \quad (\lambda_k^{Gs}, \lambda_k^{Gx}, \lambda_k^{Gr}) \tag{17}$$

We can derive the optimality conditions of the generation profit maximization as (18) to (26).

$$0 \le gopt_{h,k} \perp -\lambda_{h,i_k}^{LMP} - \lambda_{h,k}^{Credit} + CTAX_{w_k} GER_k + GVC_{h,k} + \lambda_{h,k}^{cap} \ge 0 \quad \forall h \tag{18}$$

$$0 \le cpfs_{w_k,h,k} \perp -\lambda_{w_k,h,k}^{EC} + \lambda_{h,k}^{Credit} \ge 0 \quad \forall h \tag{19}$$

$$0 \le gstat_k \perp GFOM_k \cdot GNPL_k - \sum_h HW_h \cdot GHAV_{h,k} \cdot GNPL_k \cdot \lambda_{h,k}^{cap} - \lambda_k^{Ge} + \lambda_k^{Gs} \ge 0 \tag{20}$$

$$0 \le gincexp_k \perp GEXCA_k \cdot GNPL_k + \lambda_k^{Ge} + \lambda_k^{Gx} \ge 0 \tag{21}$$

$$0 \le gincret_k \perp -\lambda_k^{Ge} + \lambda_k^{Gr} \ge 0 \tag{22}$$

$$0 \le \lambda_{h,k}^{cap} \perp -gopt_{h,k} + GNPL_k \cdot GHAV_{h,k} \cdot gstat_k \ge 0 \quad \forall h \tag{23}$$

$$\lambda_{h,k}^{Credit} \ free, \quad gopt_{h,k} - \sum_w cpfs_{w,h,k} = 0 \quad \forall h \tag{24}$$

$$\lambda_k^{Ge} \ free, \quad gstat_k - \left(GCOMI_k + gincexp_k - gincret_k\right) = 0 \tag{25}$$

$$0 \le \lambda_k^{Gs}, \lambda_k^{Gx}, \lambda_k^{Gr} \perp -\left(gstat_k, gincexp_k, gincret_k\right) + 1 \ge 0 \tag{26}$$

3.5 Load-Serving Entities

We assume that the LSE demand is purely inelastic (i.e., a fixed load), and thus the LSE is minimizing the cost of serving the load while meeting the RPS obligation. This scenario can be readily generalized to the cases in which the demand is elastic, as shown in Chen et al. (2011). However, doing so results in a nonlinear program, in general. We model LSEs at the state level, and we also assume that LSEs are the so-called "first deliverers" of electricity, a term used in the California system to assign the obligation to pay for carbon emissions. That is, an LSE is assumed to be the owner of the electricity at the first point of delivery in California and would be the point of the regulation (CARB, 2014). Consequently, LSEs are subject to BCA (boxed term in the objective function Eq. (27)). Importantly, the boxed term in the objective function is also called the "imported emissions." The deemed rate applied can vary according to the policy assumptions for the particular run. The objective function of an LSE is to minimize (27), in a manner subject to constraints (28) to (30). For simplicity, we omit "for all *w*" from the constraint domain and omit nonnegative constraints as well.

$$\text{Minimize } (\forall w) \quad CC_w = \sum_h HW_h \cdot \left(\begin{array}{l} \sum_{i \in I_w} \lambda_{h,i}^{LMP} \cdot \left(LOAD_{h,i} - n_{h,i}^{Load} \right) + \sum_{i \in I_w} VOLL \cdot n_{h,i}^{Load} \\ + ACP_w \cdot n_{w,h}^{RPS} + \sum_k \lambda_{w,h,k}^{EC} \cdot cpfb_{w,h,k} \\ \boxed{+ \sum_{k \notin K_w} CTAX_w \cdot DR_{w,h,k} \cdot cpfb_{w,h,k}} \end{array} \right) \tag{27}$$

Constraints (28) and (29) are, respectively, the general RPS requirement and the in-state RPS requirement (or, more generally, the within jurisdiction constraint, which can be a subunit of a state or collection of states; the constraint could also encompass multiple LSEs, in general). Notably, energy credits brought from other states are not eligible for meeting the in-state RPS requirement (29), but they could be used in meeting the general RPS requirement (28). Constraint (30) is a requirement for LSEs that the served load must be equal to the sum of purchased energy credit contracts, and the composition of the generation that meets the supported load will be specified at an hourly resolution.

$$\sum_h HW_h \left(n_{w,h}^{RPS} + \sum_k RE_{w,k} cpfb_{w,h,k} \right) \geq RPS_w \cdot \sum_h HW_h \cdot \left(\sum_{i \in I_w} \left(LOAD_{h,i} - n_{h,i}^{Load} \right) \right) \quad (\lambda_w^{RPS}) \tag{28}$$

$$\sum_h HW_h \left(n_{w,h}^{RPS} + \sum_{k \in K_w} RE_{w,k} cpfb_{w,h,k} \right) \geq IRPS_w \cdot \sum_h HW_h \cdot \left(\sum_{i \in I_w} \left(LOAD_{h,i} - n_{h,i}^{Load} \right) \right) \quad (\lambda_w^{IRPS}) \tag{29}$$

$$\sum_k cpfb_{w,h,k} - \sum_{i \in I_w} \left(LOAD_{h,i} - n_{h,i}^{Load} \right) = 0 \quad (\lambda_{w,h}^{Dev}) \quad \forall h \tag{30}$$

We can derive the optimality conditions of the LSE problem as in (31) to (36). The boxed item in condition (33) appears only if the LSE is located in a unilateral carbon pricing jurisdiction, and that jurisdiction chooses to implement BCA that charges imports for deemed carbon emissions.

$$0 \leq n_{w,h}^{RPS} \perp ACP_w + \lambda_{w,h}^{ACUB} - \left(\lambda_w^{RPS} + \lambda_w^{IRPS} \right) \geq 0 \quad \forall h \tag{31}$$

$$0 \leq n_{h,i}^{Load} \perp VOLL - \lambda_{h,i}^{LMP} - \lambda_{w,h}^{Dev} - RPS_w \cdot \lambda_w^{RPS} - IRPS_w \cdot \lambda_w^{IRPS} \geq 0 \quad \forall h, i \in I_w \tag{32}$$

$$\left. \begin{array}{l} 0 \leq cpfb_{w,h,k} \perp \lambda_{w,h,k}^{EC} \boxed{+CTAX_w DR_{w,h,k}} - RE_{w,k} \lambda_w^{RPS} - \lambda_{w,h}^{Dev} \geq 0 \quad \forall h, k \notin K_w \\ 0 \leq cpfb_{w,h,k} \perp \lambda_{w,h,k}^{EC} - RE_{w,k} \left(\lambda_w^{RPS} + \lambda_w^{IRPS} \right) - \lambda_{w,h}^{Dev} \geq 0 \quad \forall h, k \in K_w \end{array} \right\} \tag{33}$$

$$0 \le \lambda_w^{RPS} \perp \sum_h HW_h \cdot \left(n_{w,h}^{RPS} + \sum_k RE_{w,k} cpfb_{w,h,k} \right) - RPS_w \cdot \sum_h HW_h \cdot \left(\sum_{i \in I_w} \left(LOAD_{h,i} - n_{h,i}^{Load} \right) \right) \ge 0 \tag{34}$$

$$0 \le \lambda_w^{IRPS} \perp \sum_h HW_h \cdot \left(n_{w,h}^{RPS} + \sum_{k \in K_w} RE_{w,k} \cdot cpfb_{w,h,k} \right) - IRPS_{stt} \cdot \sum_h HW_h \left(\sum_{i \in I_w} \left(LOAD_{h,i} - n_{h,i}^{Load} \right) \right) \ge 0 \tag{35}$$

$$\lambda_{w,h}^{Dev} \ free, \quad \sum_k cpfb_{w,h,k} - \sum_{i \in I_w} \left(LOAD_{h,i} - n_{h,i}^{Load} \right) = 0 \quad \forall h \tag{36}$$

3.6 Market Clearing Conditions

There are two markets in this equilibrium: the electricity market, with its market-clearing condition (37), and the bilateral energy credit market, with its market-clearing condition (38).

$$\lambda_{i,h}^{LMP} \ free, \quad \sum_{k \in K_i} gopt_{h,k} + \sum_l LBI_{i,l} pf_{h,l} - \left(LOAD_{h,i} - n_{h,i}^{Load} \right) = 0 \quad \forall h, i \tag{37}$$

$$\lambda_{w,h,k}^{EC} \ free, \quad cpfs_{w,h,k} = cpfb_{w,h,k} = cpf_{w,h,k} \quad \forall w, h, k \tag{38}$$

3.7 An Equivalent Single Optimization

A single optimization exists that is equivalent to the equilibrium problem comprising the problems of GenCos, LSEs, and the ISO in the above subsections. The objective function of this single optimization is to minimize Eq. (39), which is the sum of all individual objectives. Of note, the boxed term appears only when the carbon pricing regime charges the import at the assumed carbon tax/price. The boxed term is the total payment from the LSEs to the emission regulator (which is not a market party within the model), owing to the imported energy credit contracts. By leaving out the emission regulator's revenues from the objective, this model simulates the actions of market parties in response to an emissions permit cost or tax.

$$\begin{aligned}
\text{Minimize}\quad SC &= \sum_w CC_w - \sum_k GP_k - ISO \\
&= \sum_h HW_h \cdot \left(\sum_i VOLL \cdot n_{h,i}^{Load} \right) + \sum_h HW_h \cdot \left(\sum_w ACP_w \cdot n_{w,h}^{RPS} \right) \\
&\quad + \boxed{\sum_h HW_h \cdot \left(\sum_{w,k \notin K_w} CTAX_w \cdot DR_{w,h,k} \cdot cpfb_{w,h,k} \right)} \\
&\quad + \sum_h HW_h \cdot \left(\sum_k GVC_{h,k} \cdot gopt_{h,k} \right) + \sum_h HW_h \cdot \left(\sum_k CTAX_{w_k} \cdot GER_k \cdot gopt_{h,k} \right) \\
&\quad + \sum_k GEXCA_k \cdot GNPL_k \cdot gincexp_k + \sum_k GFOM_k \cdot GNPL_k \cdot gstat_k \\
&\quad + \sum_l LEXCA_l \cdot lincexp_l
\end{aligned} \tag{39}$$

The constraints are the union of all individual operation and construction constraints, as well as the market-clearing conditions, that appear in the above subsection. That is, the constraints of the single optimization include (2)–(5), (14)–(17), (28)–(30), (37), and (38). As first shown in Samuelson (1952) and applied in Chen et al. (2011), there is a one-to-one correspondence between (i) all optimality conditions (not shown) of this single optimization and (ii) the union of the optimality conditions of the individual problems and market clearing constraints shown above. Thus, the following is implied: if a solution exists to the equilibrium problem, i.e., the union of market party KKT conditions and market clearing conditions in Sections 3.3 to 3.6, it will also be an optimal solution for the single optimization constituted by objective function, e.g., (39) and associated constraints, and vice versa. Furthermore, if one is unique, so is the other. Therefore, we should be able to obtain an equilibrium solution for the market by solving the single optimization problem. Therefore, in the remainder of the analysis, we can, and do, solve a single optimization equivalent to the market equilibrium problem to simulate the market outcomes under alternative BCA schemes.

4 Experimental Design

4.1 Candidate Deemed Rate Schemes

Table 2. summarizes several possible modifications of the current implementation of AB32 in California (CARB, 2014) that we considered in our policy simulations of BCA schemes.

Table 2. Alternative Carbon Border Tax Adjustment Schemes

Case ID	Deemed Rate Scheme
1	No BCA, or DR = 0 tons/MWh
2	Constant and Facility-based
3	Constant and Facility-neutral
4.a	Dynamic and Facility-neutral: Internal Marginal
4.b	Dynamic and Facility-neutral: External Marginal
4.c	Dynamic and Facility-neutral: Internal Average
4.d	Dynamic and Facility-neutral: External Average

Cases 1–4 (Table 2) differ in how the parameter set $DR_{w,h,k}$ is calculated. The DR is defined as how much CO_2e emissions the regulator assigns to each energy credit transaction. For simplicity, the dimension of CO_2e (metric tons) is hereafter is referred to as tons. The first and simplest DR setting is DR = 0 tons/MWh. A DR of zero is the same as the pure supply side/source-based carbon pricing case in which only California sources are regulated because LSEs have no responsibility to report the imported emission and surrender the associated allowances.

The second DR setting (Case 2, Table 2) is based on the supply side of a contract, as currently implemented in the California carbon pricing system, in which the first deliverer (importer) must specify the source of emission associated with the contract and surrender the associated emission allowances in proportion to the source's emissions.[5]

The third DR setting (Case 3, Table 2) involves applying a uniform DR for all contracts at all times, i.e., a constant and technology-neutral DR. We test a range of DRs from 0.02 to 0.50 tons/MWh with a step size of 0.02 tons/MWh, with the upper limit corresponding to the emission rate of a typical natural gas combustion turbine.

There are four subtypes of the dynamic and facility-neutral DR setting, i.e., 4.a to 4.d. The DR settings Cases (4.a) and (4.b) apply a dynamic technology-neutral DR and are based on the

[5] If the first deliverer cannot (or chooses not to) specify the source, an "unspecified-source" emission will apply at 0.428 tons/MWh (Bushnell et al., 2014; Pavley, 2016). Intuitively, this scenario provides an approach for coal plants to mask their emissions by not reporting the source but may also be viewed as penalizing renewable sources whose emissions are below that rate. Because the cost of source-specification is difficult to estimate, we simulate two extremes in this paper. One extreme is with 100% source-specification (i.e., Case 2), in which the cost of identifying sources of import is assumed negligible. The other extreme is with 0% source-specification, and the cost of source-specification is assumed sufficiently large that not specifying the source is economical. The latter is modeled as one special case in Case 3, in which the constant DR is set to approximately 0.44 tons/MWh. In practice, the importer can specify the source of the import transaction with an E-tag, which includes the information of the source, sink, physical path, and time of the transaction; however, this process involves some expense.

marginal emissions *internal* or *external* to the carbon pricing jurisdiction, respectively; that is, the DR for each hour is defined as *how much emissions change internally (or externally) in the carbon pricing jurisdiction if the state-level load served by internal (external) sources varies by 1 unit.* Of note, here we calculate short-run marginal emissions with fixed generation capacity, rather than long-run marginal emissions that would arise if generation capacity changes are considered. As described in Section 1, setting the DR according to the marginal emissions of internal generators follows the logic of "the carbon pricing policy rais(ing) the cost of marginal units, which in turn sets the electricity prices" (NYISO, 2018). Thus, by basing the DR on internal marginal emissions, the regulator can roll back the extra payment to the outside generators caused by internal carbon pricing (ibid.). In this sense, alternative Case (4.a) here is closest to the NYISO proposal (ibid.). Deemed rate settings (4.c) and (4.d) also apply time-varying DRs, but they are based on average, rather than marginal, emissions internal or external to the carbon pricing jurisdiction, respectively.

To calculate the marginal emissions in Cases (4.a) and (4.b), we raise the load of the carbon pricing jurisdiction (in this case, California) by a small incremental amount each hour. We do so by moving up the energy demand on every bus inside the state in proportion to the original demand (Eq. (40) below uses California as an example). Then, the model is re-dispatched for the entire multistate system; the incremental system-wide emissions are the marginal emissions with respect to the demand increase. This total is then apportioned to internal and external emission rates as follows. External marginal emission rates are calculated by dividing the incremental external emissions by the incremental external generation. Internal marginal emission rates are instead obtained by dividing the incremental internal emissions by the incremental internal generation. Of note, in calculating the external marginal emission rate, all the incremental generation of interest might possibly be from inside the state, thus making the denominator equal to zero (or vice versa); in that case, the marginal emission rate is set to zero.

$$LOAD_{h,i}^{\text{Newdispatch}} = LOAD_{h,i} + \Delta \cdot \frac{LOAD_{h,i}}{\sum_{i' \in I_{CA}} LOAD_{h,i'}} \quad \forall i \in I_{CA} \tag{40}$$

$$\left.\begin{aligned}MER_h^{\text{Internal}} &= \frac{\sum_{k\in K_{CA}} GER_k \cdot gopt_{h,k}^{\text{Newdispatch}} - \sum_{k\in K_{CA}} GER_k \cdot gopt_{h,k}}{\sum_{k\in K_{CA}} gopt_{h,k}^{\text{Newdispatch}} - \sum_{k\in K_{CA}} gopt_{h,k}} \\ MER_h^{\text{External}} &= \frac{\sum_{k\notin K_{CA}} GER_k \cdot gopt_{h,k}^{\text{Newdispatch}} - \sum_{k\notin K_{CA}} GER_k \cdot gopt_{h,k}}{\sum_{k\notin K_{CA}} gopt_{h,k}^{\text{Newdispatch}} - \sum_{k\notin K_{CA}} gopt_{h,k}}\end{aligned}\right\} \tag{41}$$

Meanwhile, the average emissions rate calculation does not involve re-dispatch and equals:

$$AER_h^{\text{Internal}} = \frac{\sum_{k\in K_{CA}} GER_k \cdot gopt_{h,k}}{\sum_{k\in K_{CA}} gopt_{h,k}}, AER_h^{\text{External}} = \frac{\sum_{k\notin K_{CA}} GER_k \cdot gopt_{h,k}}{\sum_{k\notin K_{CA}} gopt_{h,k}} \tag{42}$$

In summary, we test all six alternative DR schemes, some of which may involve additional calculations, since marginal emissions rates are endogenous. Next, we summarize the use of the Gauss-Seidel iteration approach to calculate dynamic DRs.

4.2 Solving for Dynamic Deemed Emission Rates – A Fixed Point Problem

Finding the dynamic DRs in Case 4 is essentially finding the solution to a fixed-point problem. As a demonstration, let the procedure of calculating the marginal/average emission rate (i.e., Equations (40) to (42)) be represented as a fixed point problem in which we are attempting to find the solutions **x***, **y***, **DR** to the following vector-valued function

$$\mathbf{DR} = f_{ER}\left(\mathbf{x}^*, \mathbf{y}^* \mid \mathbf{DR}\right),$$

where (**x***, **y***) represents the vector comprising the optimal solution of investment decision **x** and operation simulation **y**, minimizing the societal cost, given a vector of **DR** and other parameters (not shown). That is, (**x***, **y***) satisfies the following:

$$\left(\mathbf{x}^*, \mathbf{y}^*\right) = \arg\min_{(\mathbf{x},\mathbf{y})\in\mathbf{F}} SC(\mathbf{x}, \mathbf{y} \mid \mathbf{DR})$$

where **F** indicates the feasible region, and *SC* is the societal cost defined in the previous section. Thus, finding a DR equal to the marginal/average emission rate essentially involves calculating the following fixed-point problem:

$$\mathbf{DR} = f_{ER}(\mathbf{x}^*, \mathbf{y}^*) = f_{ER}(\arg\min_{\mathbf{x},\mathbf{y}\in\mathbf{F}} SC(\mathbf{x}, \mathbf{y} \mid \mathbf{DR}))$$

This fixed-point problem corresponds to a cat-and-mouse game between the regulator and the power sector participants (as seen in the two-node example in Section 2). Initially, suppose that the regulator sets the DR at some nominal marginal (or average) emission rate, $\mathbf{DR^o}$ (which might be estimated from previous periods, for instance) and gives the system another chance to re-dispatch. Consequently, the new marginal generators (and emissions $\mathbf{DR^1}$) might differ from those in the previous periods, or the total emissions might change (Fig. 2, inner feedback loop). Generation and transmission expansion decisions will affect the dispatch results, marginal/average emissions, and DRs; the dispatch resulting in each hour will in turn change the value of generation and transmission addition, and affect the expansion decision (Fig. 2, outer feedback loop).

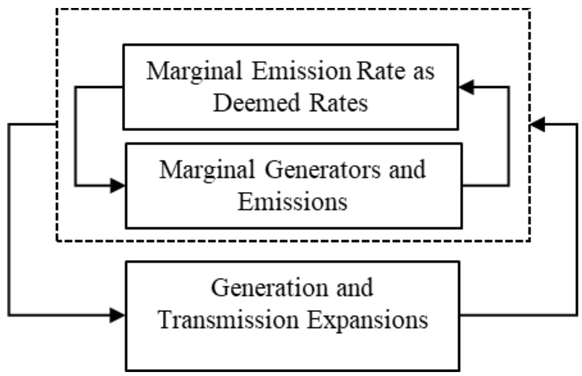

Fig. 2. Deemed rate (if set according to the marginal emission rate) influences the marginal generator and vice versa.

In this analysis, we use a double-loop fixed-point iteration algorithm in Fig. 3 to attempt to find the solution to this fixed-point problem. Please note that a fixed point may not exist, or if it does exist, the algorithm may be unsuccessful in finding it. Outer Loop A (yellow box, Fig. 3) explicitly models the interaction between investment $\mathbf{x}$ and the market operation and DR setting ($\mathbf{y}$, $\mathbf{DR}$). We define the convergence of Loop A when the change in the objective function value (SC, societal cost) between Loop A iterations is sufficiently small (i.e., $< \varepsilon_A = 0.1\%$). The inner Loop B (gray box, Fig. 3), in contrast, is a fixed point iteration to find the DR with a fixed generation and transmission expansion plan, that is, modeling the interaction between market operation $\mathbf{y}$ and the DR setting ($\mathbf{DR}$). We define the convergence of Loop B as a sufficiently small mean deviation of DRs between Loop B iterations (i.e., $< \varepsilon_B = 0.01$ tons/MWh).

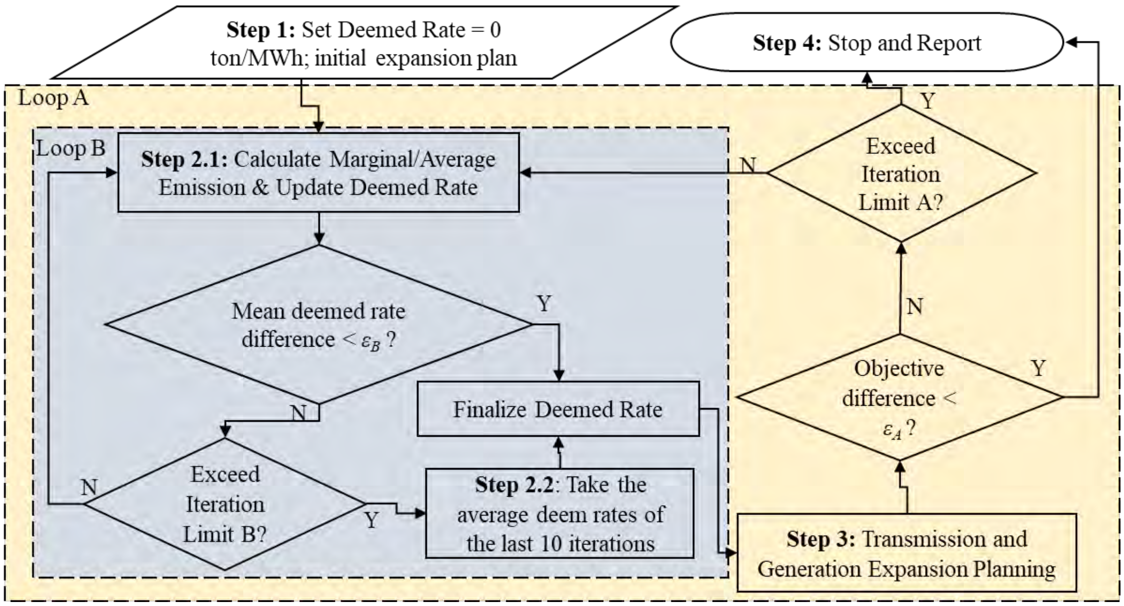

Fig. 3. Diagram of the algorithm of modeling time-varying DR based on marginal and average emission rate.

Loop B is a Gauss-Seidel fixed point iteration between the following two steps:

$$\tilde{\mathbf{y}} \leftarrow \arg\min_{\mathbf{x},\mathbf{y}\in\mathbf{F}} SC\left(\mathbf{x}=\mathbf{x}^A, \mathbf{y} \mid \mathbf{DR}\right),$$

$$\mathbf{DR} \leftarrow f_{ER}\left(\mathbf{x}^A, \tilde{\mathbf{y}}\right),$$

where $\mathbf{x}^A$ is the fixed expansion plan from outer Loop A. We do not attempt to demonstrate either the existence or the convergence of such Gauss-Seidel iteration in this work. However, the method is a widely used approach in the energy modeling literature, and some analysis of its convergence properties has been described in the context of other applications (Greenberg and Murphy, 1985).

4.3 Experimental Setting – WECC system

We test each BCA scheme in Table 2, with five assumed Californian carbon price realizations: 0 to \$80/tons CO_2e with a \$20/ton incremental step.[6] In this set of analyses, we run the model (Section 3) for the WECC in the year 2034. The system is a reduced network based on

[6] At the time of writing, the most recent five rounds of the California-Quebec joint auction of carbon allowance have yielded allowance prices of \$15.05/ton to \$17.16/ton, showing an increasing trend over time (CARB, 2019b). The \$20/ton value is selected herein as a reasonable price close to price levels today, whereas \$40/ton is selected as a high carbon price case. This \$40/ton is approximately the same as the current carbon tax in British Columbia, Canada of \$50/ton with an exchange rate of 1.25 CA\$ to 1.00 US\$ (Morneau, 2018). Other prices are selected to test the sensitivity of the results.

the 2026 Common Case of the WECC (WECC, 2017) with 361 buses and 712 transmission lines using the network reduction method developed in Zhu and Tylavsky (2018). A map of the network is shown in Fig. 4.

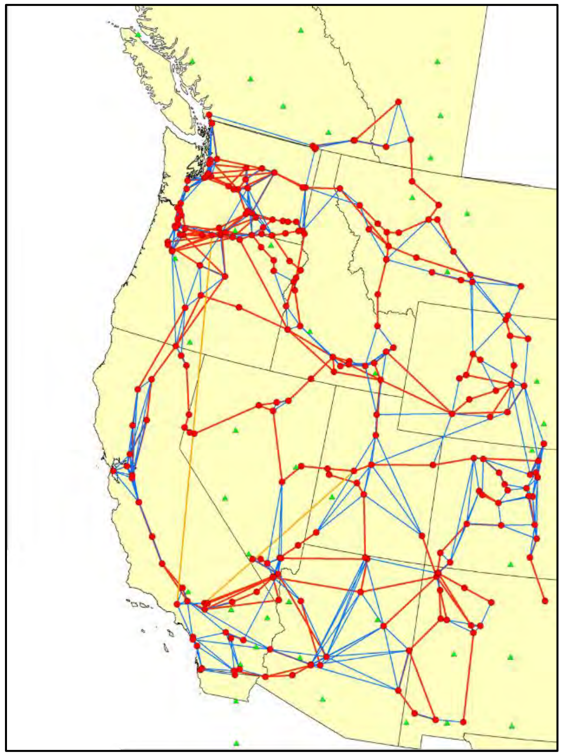

Fig. 4. Map of the test system. Red dots are buses, and green triangles are renewable generation candidates. Red lines are existing AC lines, and orange lines are existing high-voltage DC lines. Blue lines are the equivalent lines resulting from network reduction.

There are 1504 aggregated existing generators and 810 candidates, spanning 32 technologies, including coal, gas (combined cycle and combustion turbine), nuclear, wind, solar, geothermal, and biofuel. Only gas generation can be built as conventional thermal generators with a 5-GW limit on each bus, whereas renewables, i.e., wind, solar, biofuel, and geothermal, can be expanded at only 53 candidate sites and would need new transmission lines to be connected to the grid. These 53 candidate sites (in addition to the existing 361 buses) and their maximum installed capacities are identified in Western Governors' Association and USDOE (2009). Specifically, we double the renewable potential at the 5 sites in California to avoid situations in which California could potentially deplete its renewable energy potential. All assumed capital costs of generation expansion are based on WECC and Energy and Environmental Economics (2017) and are differentiated by location.

Transmission line candidates are categorized into two types: backbone reinforcements and renewable connections. There are 54 reinforcement candidates for additions to the backbone network in Fig. 4, most of which are additions in transfer capability for existing corridors. In addition, there are 104 renewable connection candidates that can be developed to connect the 53 candidate sites. Transmission expansion candidate costs are calculated on the basis of the length of the transmission line, width, type of land-use, and voltage level, by using the base cost of the conductors and substations, as found in WECC (2014). Four days (96 hours) are simulated to represent the year 2034.

RPS data for the year 2034 are from DSIRE (DSIRE, 2018), and demand data are from WECC-LTPT (WECC, 2016). Because state-level RPS policies do not include every type of utility in the state, we adjust the requirement according to the share of the total electricity sales covered by RPS. In cases in which the RPS data for 2034 are unavailable, we assume that the RPS will remain at the latest specified number. The alternative compliance penalty is \$100/MWh for all states with RPS; i.e., if there is a renewable energy capacity shortage, the LSE must pay such a penalty (or buy renewable credits from the state government) to fulfill the RPS requirement. The RPS requirements used in this work are shown in Table 3. For British Columbia, there is a \$40/ton carbon tax, but no BCA is implemented.

Table 3. Assumed RPS Requirements in 2034

State or Province	RPS	State	RPS
Alberta	30.0%	Mexico	0.0%
Arizona	14.6%	New Mexico	16.1%
British Columbia**	93.0%	Nevada	22.8%
California*	59.3%	Oregon	35.2%
Colorado	21.0%	Utah	0.0%
Idaho	0.0%	Washington	13.1%
Montana	13.4%	Wyoming	0.0%

* CA also requires 75% of the RPS requirement to be met by in-state renewable generation

** All WECC regions except British Columbia are assumed to consider generation from large (>20 MW) hydroelectric facilities as non-renewable

We place some restrictions on interstate energy credit trading. First, in the case of existing generation capacity, only those nodes with an aggregate capacity >200 MW can sell energy credits out of state, under the assumption that exporting power to California is difficult for small generators. However, most of the capacity in the rest of WECC (ROW), including wind and solar, is located at nodes that meet this threshold. Second, for any plant, energy credits can be sold to only the home state, the neighboring state, or the state adjacent to a neighboring state. We also introduce several simplifications of the model setup to accelerate the solution process. For example, power flow is modeled with a transshipment power flow model rather than as a DC load flow, transmission and generation capacity can be expanded in continuous amounts rather than fixed increments, and unit commitment and storage expansion are not included. At the expense of larger models and slower computation times, these complications could be included.

5 Results

This section summarizes the comparative statics of the alternative BCA schemes based on alternative deemed rates (Table 2). First, we first examine the dynamic properties of marginal/average emission rates resulting from calculation of the dynamic DRs. We then examine the impacts of adopting different BCA DR schemes. The impact metrics include overall regional (WECC) carbon emissions, indicators of emission leakage based on the distributions of carbon emissions between California and the Rest of WECC (ROW), distribution of electricity production among states and generation types, total market costs, and California consumer payments. Although our emphasis is on overall efficiency (the minimum market cost of achieving alternative targets for emissions reduction), the other metrics shed light on trade-offs between the local and regional objectives, and can help California policymakers understand the impacts of the policy on their consumers and voters.

5.1 Dynamic Marginal and Average Emission Rates

In determining DRs, it is important to understand how marginal/average emissions rates vary over time. Fig. 5 shows California's marginal emission rates of internal and external generators at different hours on one of the four days as an example (Sept 30th, 2034). Several observations can be made. First, short-run marginal emission rates indeed vary at different hours, i.e., the rates are dynamic, ranging from 0 to approximately 0.7 tons/MWh. Second, the internal and external marginal emission rates are significantly different at several hours.

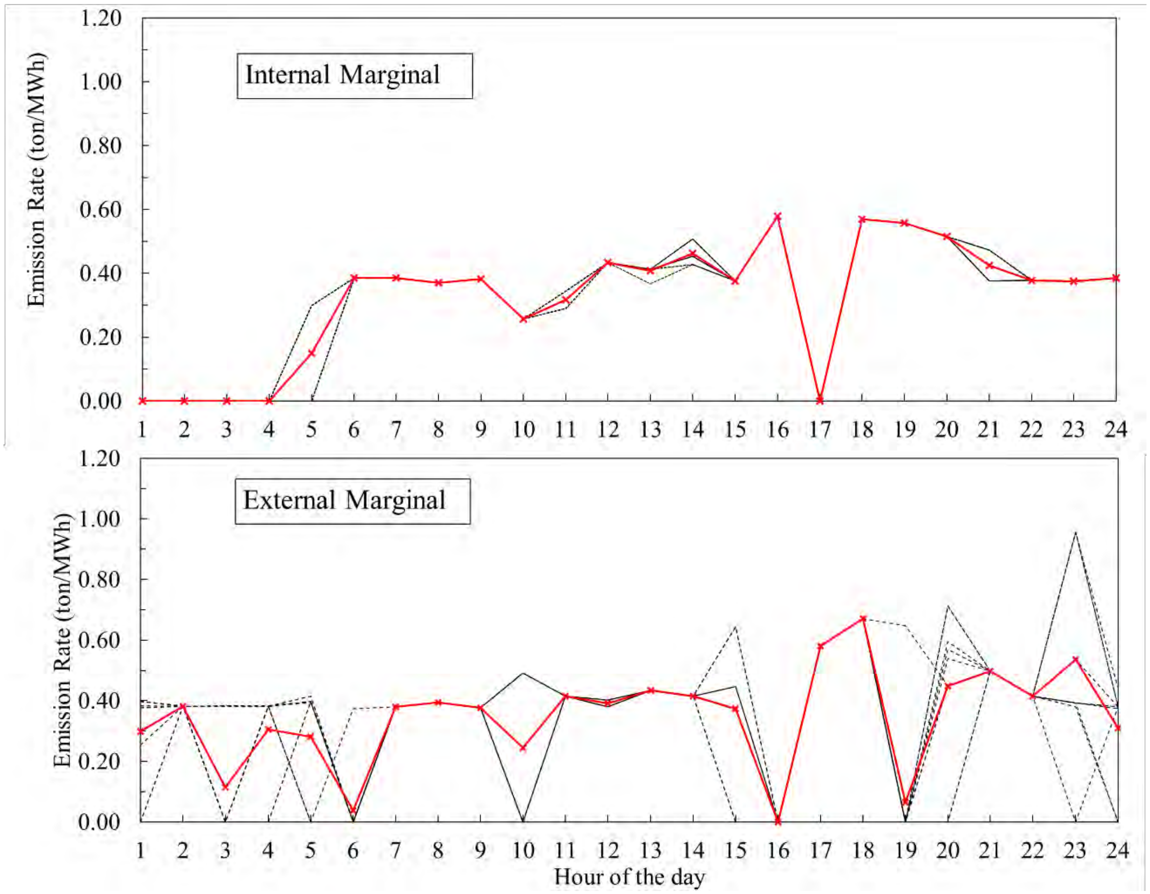

Fig. 5. Marginal emission rates (internal (up) and external (bottom) to California) for the last ten (10) iterations (dotted lines) and their average (red line with cross marks) (carbon price = \$40/ton, September 30th, 2034).

The average emission rates for one day are shown in Fig. 6. Similar results are observed for the other three days simulated in 2034. Overall, the average emission rates show more stability over the hours than the marginal emission rates. The average emission rates of external generators are universally higher than their internal counterparts and are less variable because California is a relatively clean state with almost no coal capacity (except in the must-run combined heat and power plants) and more renewable resources, including solar, wind, and geothermal capacity.

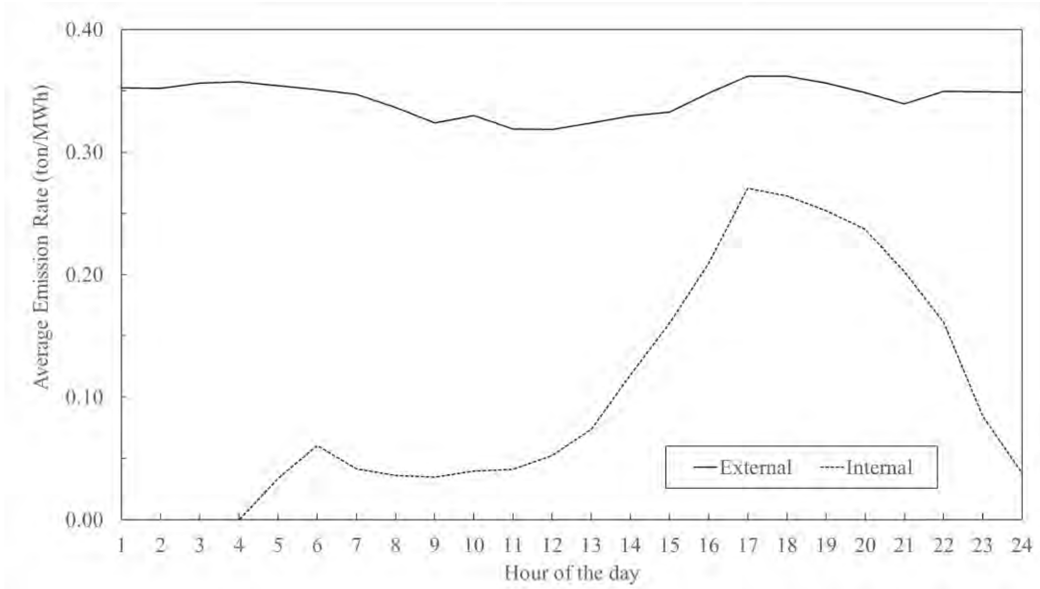

Fig. 6. Average emission rate (internal and external to California, carbon price = \$40/ton, September 30th, 2034).

5.2 Emission and Generation Distributions from Alternative DR Schemes

As illustrated in the simple case in Section 2, BCA with facility-based DR can be ineffective to mitigate the leakage caused by unilateral carbon pricing, but a DR scheme that is indifferent to import sources can mitigate leakage by eliminating incentives to shuffle contracts. Fig. 7 shows a similar story in the complex system by the results of emission distributions for all investigated DR schemes (Cases 1-4). As a reference, without California's carbon price, our model shows that in 2034, WECC emits 281.27 Mtons/year in total, of which California accounts for 30.09 Mtons/year and the ROW 251.18 Mtons/year (shown as the horizontal lines in Fig. 7). As a comparison, in 2017, California reported a carbon emission of 38.58 Mtons from in-state generators (CARB, 2019a).

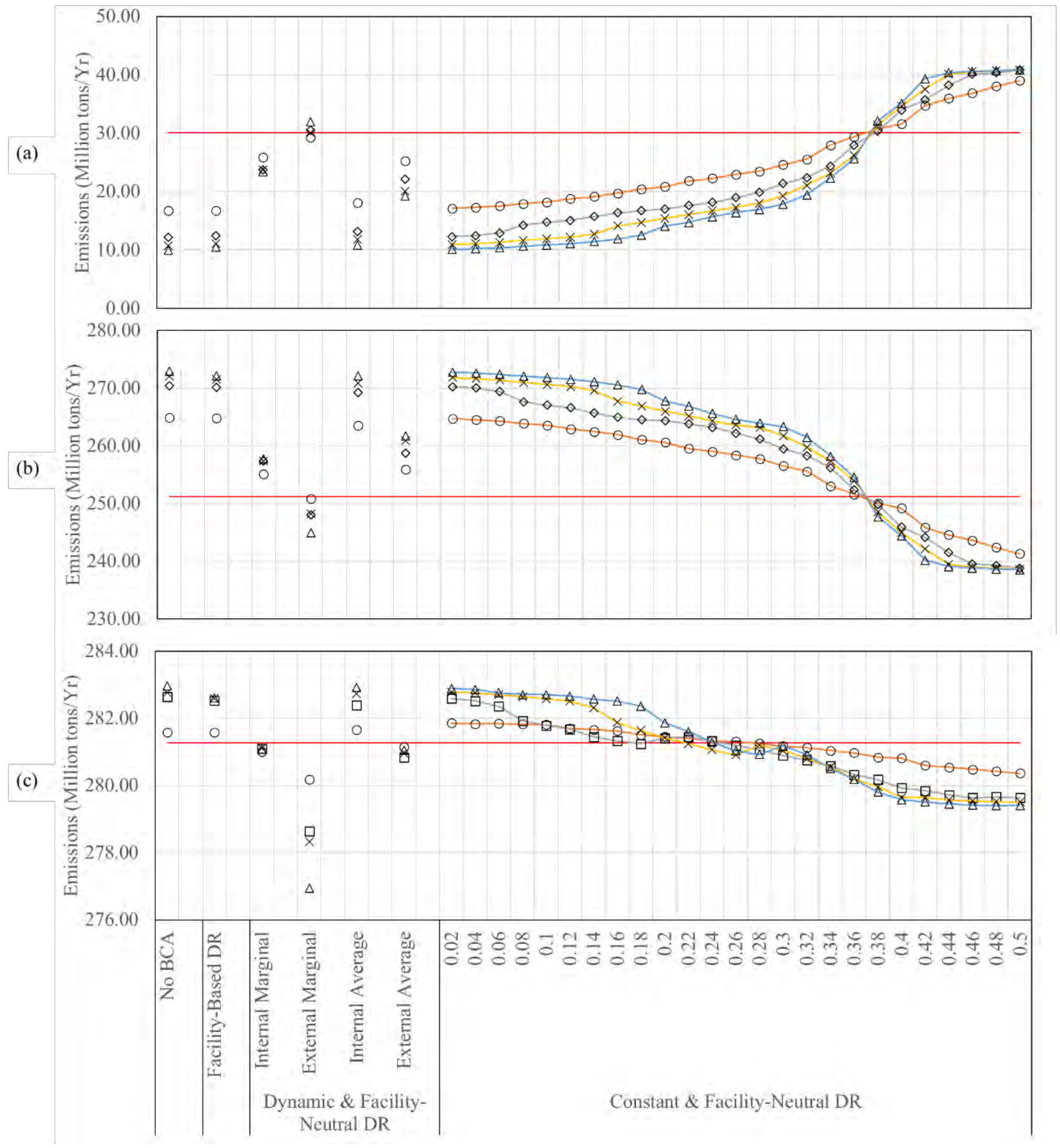

Fig. 7. Carbon emissions of California (a), the rest of the WECC (b), and WECC total (c), with different DR schemes and carbon prices, in the year 2034. Horizontal red line represents the emission level without the California carbon price.

Our first observation is that carbon pricing within California can *increase* WECC-wide emissions, resulting from the possibility that physical carbon leakage can exceed 100%, similar to the simple case in Section 2. This happens because the increased electricity production from ROW is supported by gas-fired power plants that are less efficient (i.e., have higher heat rates) than the California ones that are shut down because of the carbon pricing. Essentially, there are two possible outcomes of having local carbon pricing. Because of the carbon pricing, the local gas-fired plant becomes more expensive, and it is more economical to switch either to local renewable generators or to import more. Given that the aggressive RPS already supports local renewable generators, the economical option is more imports. The system chooses not to build and dispatch more emitting-free renewable generation for incremental imports because of two reasons: (a) the units already exists and have been fully dispatched without California carbon pricing, or (b) building new ones is more expensive than shuffling contracts.

The increase of WECC-wide emissions occurs when any of the following schemes are implemented: (i) a facility-based DR scheme; (ii) a constant, facility-neutral, but low DR, or (iii) a dynamic DR is chosen based on the internal average emission rate. For the latter case, the large amount of leakage is because the DRs, though dynamic, are frequently low. Furthermore, as might be expected, carbon leakage *worsens* when carbon prices are higher. For instance, among all investigated DR schemes, the highest WECC-wide emission increase results from the no BCA case (DR = 0 tons/MWh) while the carbon price is $80/ton; in that case, California's emissions decrease by 20.13 Mtons/year relative to no carbon policy, but the ROW emissions *increase* by 21.82 Mtons/year, thus increasing system-wide emissions of 1.69 Mtons/year. We are not saying that this is the present effect (or lack thereof) of AB32, but are pointing out that this is a risk under some possible future conditions under this particular BCA policy.

The impacts of various DR schemes on emission share one commonality: all show a major shift in emissions between California and the ROW. Although the volume of this emission shift is large (e.g., parts (a) and (b) of Fig. 7 show emissions of different schemes differing by as much as 30 Mtons/year, which is the same order of magnitude as all of California's emissions), the system-wide emission reductions are much more limited (Fig. 7(c) has a range of 6 Mtons/year).

Finally, in each carbon price case, the largest reduction in system-wide emissions is achieved by setting a dynamic DR according to the external marginal emission rate. For instance, when the carbon price is $80/ton, Fig. 7 (c) shows that DRs set by an external marginal emission rate cut the WECC-wide emissions by 4.33 Mtons/years, and the second-largest emission reduction is 1.87 Mtons/year when DR is a constant 0.5 tons/MWh. This dynamic DR achieves the most emission reduction by setting a "high" emission rate at the "right" time, i.e., when coal-fired power is the marginal source of power in the ROW and thus the major cause of leakage when California imports increase due to carbon pricing.

DR schemes change the locations of emissions by shifting gas power generation between California and ROW. Table 4 shows the generation mixes of California, the ROW, and WECC total if California were to adopt no carbon prices. In contrast, Fig. 8 shows the change in the generation mixes when the carbon price is $80/ton under different DR schemes. The patterns of impacts of other carbon prices are similar (not shown). For instance, in cases in which constant and facility-neutral DR is implemented, the higher DR makes imports more expensive. Consequently, California will choose to rely on more internal gas power from inside, and California's emissions will grow substantially. However, because California has implemented an aggressive (60%) RPS rule, we observe no significant impact of California carbon pricing on renewables.

Furthermore, only the dynamic DR set by an external marginal emission rate can make a significant dent in coal-fired production in ROW (e.g., 5.74 TWh/year when the carbon price is $80/ton in Fig. 8(b), from 174.10 TWh/year (Table 4) under no regulation to 168.36 TWh under the policy). Again, this outcome is because a high DR is set when the marginal units supporting California's load are largely coal power plants. This impact strongly depends on the carbon price that the coal production reduction is lower with lower carbon price (2.86 TWh/year cut when California carbon price = $40/ton).

Table 4. Generation Mixes of California, the Rest of the WECC, and WECC total, when the California Carbon Price is $0/ton, in the Year 2034

Units: TWh/yr		California	Rest of WECC	WECC Total
Existing Emission Free	Bio	11.61	13.17	24.78
	Geo	23.58	13.07	36.65
	Hydro	25.84	205.82	231.66
	Nuclear	0	44.75	44.75
	Solar	13.65	9.07	22.72
	Wind	23.69	52.96	76.65
	Subtotal	98.37	338.84	437.21
New Renewable	Bio	1.76	0	1.76
	Geo	23.81	21.12	44.93
	Solar	41.13	10.70	51.83
	Wind	11.13	62.42	73.55
	Subtotal	77.83	94.24	172.07
Existing Coal		1.17	174.10	175.27
Existing Natural Gas		75.48	174.90	250.38
New Natural Gas		3.86	53.19	57.05
	Total	256.71	835.29	1092.00

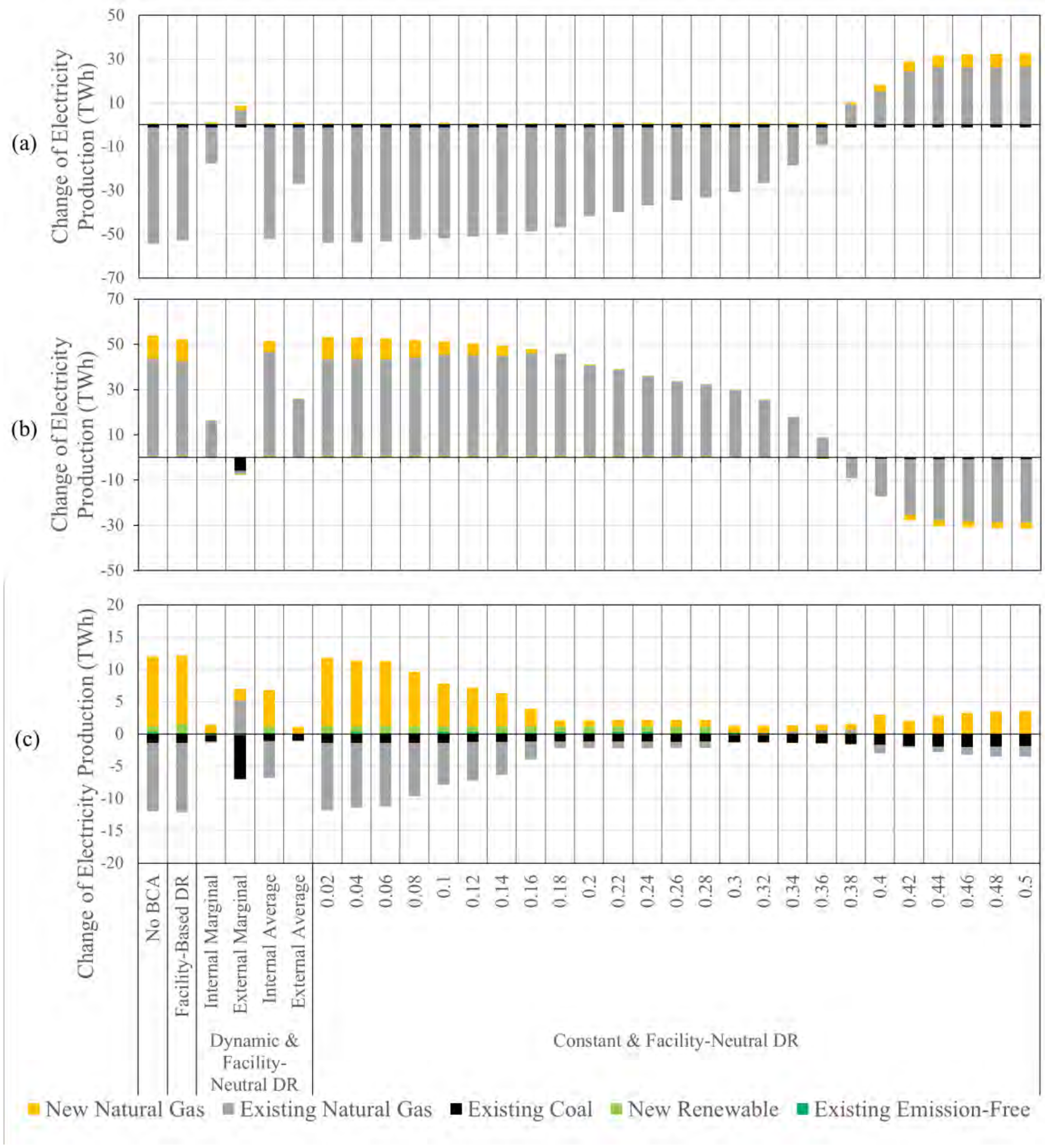

Fig. 8. Change in Generation mixes of (a) California, the (b) Rest of the WECC, and (c) WECC total, when the carbon price is \$80/ton, in the year 2034, compared with the case without a carbon price.

5.3 Accounting Carbon Leakage

The tonnage of carbon leakage has been explored in the previous section, in which the results of Fig. 7(a) and (b) show, for example, large decreases in California emissions are generally accompanied by compensating increases in ROW emissions. Policies that prevent leakage, such as a high constant DR, can bring gas-power-generated emissions back to California and thus reduce the leakage. Those policies for which Fig. 7(c) shows increases in total emissions imply that leakage exceeds the internal California emissions reductions in those cases; therefore, a physical leakage rate higher than 100%. As a reminder, the physical leakage rate is calculated as 100%× (ROW emission increases)/(California emission reductions). The result of a physical leakage exceeding 100% has been reported by Babiker (2005) at 130% using computable general equilibrium (CGE) models for homogenous products between OECD countries and the rest of the globe. Furthermore, for the California carbon pricing system, the highest estimated leakage (100%) is by Bushnell et al. (2014) in an engineering-economic simulation with 2007 data. Lower physical leakage rates for the California system have also been reported: using a CGE model, Caron et al. (2015) calculate a physical leakage rate at 45% without BCA and 9% if BCA is implemented and reshuffling is banned. However, we should recognize that the tracking and banning of reshuffling are nearly impossible, and our market models do not restrict reshuffling, consistent with California law. These assumptions contribute to the high physical leakage rate that we estimate.

The relative (percentage) accounting leakage metrics tell a slightly different story (Fig. 9). In calculating leakage amounts, it is necessary to have a baseline imputation of carbon dioxide associated with imports when there is no carbon policy. However, this is ambiguous because there are multiple alternative optima involving different contracted flows. To avoid artifactual exaggeration of leakage, the base amount of imputed carbon dioxide in imports is taken from a $0/ton solution with minimum imputed carbon inflows.

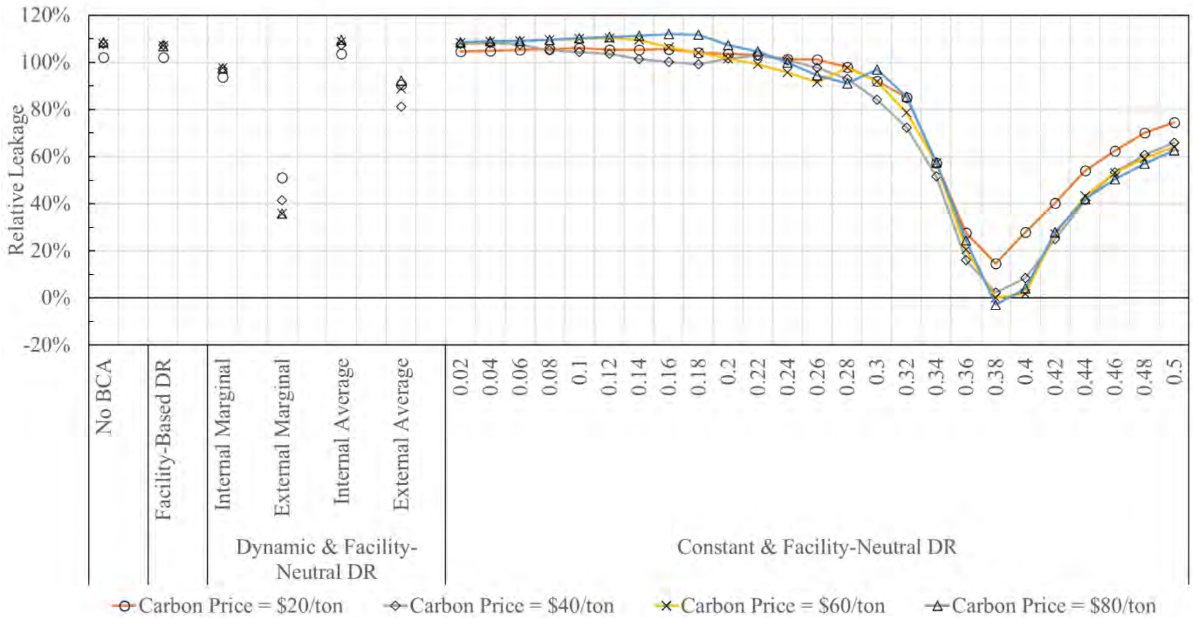

Fig. 9. Relative leakage (100% - system-wide emission reduction/regulated emission reduction) from cases with different DR schemes with different carbon prices, in the year 2034.

Several conclusions can be drawn from Fig. 9's summary of percentage accounting leakage values under different policies. First, facility-based DR, the current practice in California's implementation of carbon pricing, leads to a leakage >100% because of the increase in the WECC total emissions. As described before, the relative leakage is calculated as the relative difference between system-wide emission reduction and the reduction in regulated emissions (internal plus deemed carbon in imports), and a non-zero leakage indicates a mismatch between total WECC emissions and California emissions, which is equivalent to a divergence of the imputed imported emission reduction and actual ROW emission reduction.

Second, the minimum leakage (which is actually negative on occasion) always occurs when the DR is set to a constant 0.38 tons/MWh. Because the minimum occurs at this value, we conclude that these DRs estimate the ROW emission reduction most accurately on an annual average basis.

Finally, a close-to-zero relative leakage intriguingly does not necessarily lead to the maximum system-wide emission reduction, which instead occurs when the external marginal emission rate sets the dynamic DR. The leakage when system-wide emission reduction is maximized is approximately 36% to 51%, depending on the carbon price. This indicates that the goal of local carbon policy should not be to minimize leakage as a goal in and of itself.

5.4 Transmission Expansion

As shown in the simple model of Section 2, unilateral carbon prices and different choices of BCA affect the economic value of transmission and thus differ in the incentives they provide for grid reinforcements. Before summarizing the quantitative results, we reiterate that, as described in Section 4, two different sets of transmission expansion candidates are available in JHSMINE: (i) renewable interconnectors that deliver renewable generation to the grid and (ii) reinforcements of the grid's backbone of transmission lines. Because all renewable generation investments require connections to the grid to deliver their output, the impact of alternative DR schemes on renewable interconnectors is implicit in the results of Section 6.2: under our case study assumptions, DR schemes that penalize only imports with different DRs have a negligible influence on the expansion of renewable interconnectors, because there is little or even negative impact on the renewable capacity itself (Fig. 8(a).)

Consequently, in this section, we focus on backbone transmission investment impacts here, particularly interstate transmission expansion. Fig. 10 shows two examples of effects on interstate transmission corridors when the California emission regulator implements various DR schemes under a range of carbon price scenarios. First, implementing carbon pricing generally encourages more interstate transmission, and this effect is higher at greater carbon prices (compare the red lines and other solutions in Fig. 10). Because the economic value of transmission between California and the ROW is largely derived from delivering power into California, less California local production for any reason incentivizes more transmission build-out between California and the ROW. But because the major effect of an effective BCA scheme is to return power generation back to California, such schemes lead to less transmission build-out between California and the ROW than ineffective schemes. For instance, when the carbon price is \$20/ton and no BCA is implemented, the investment in transmission between California and Oregon is 775 MW; build-out drops to zero if a fixed DR higher than approximately 0.3 tons/MWh is set.

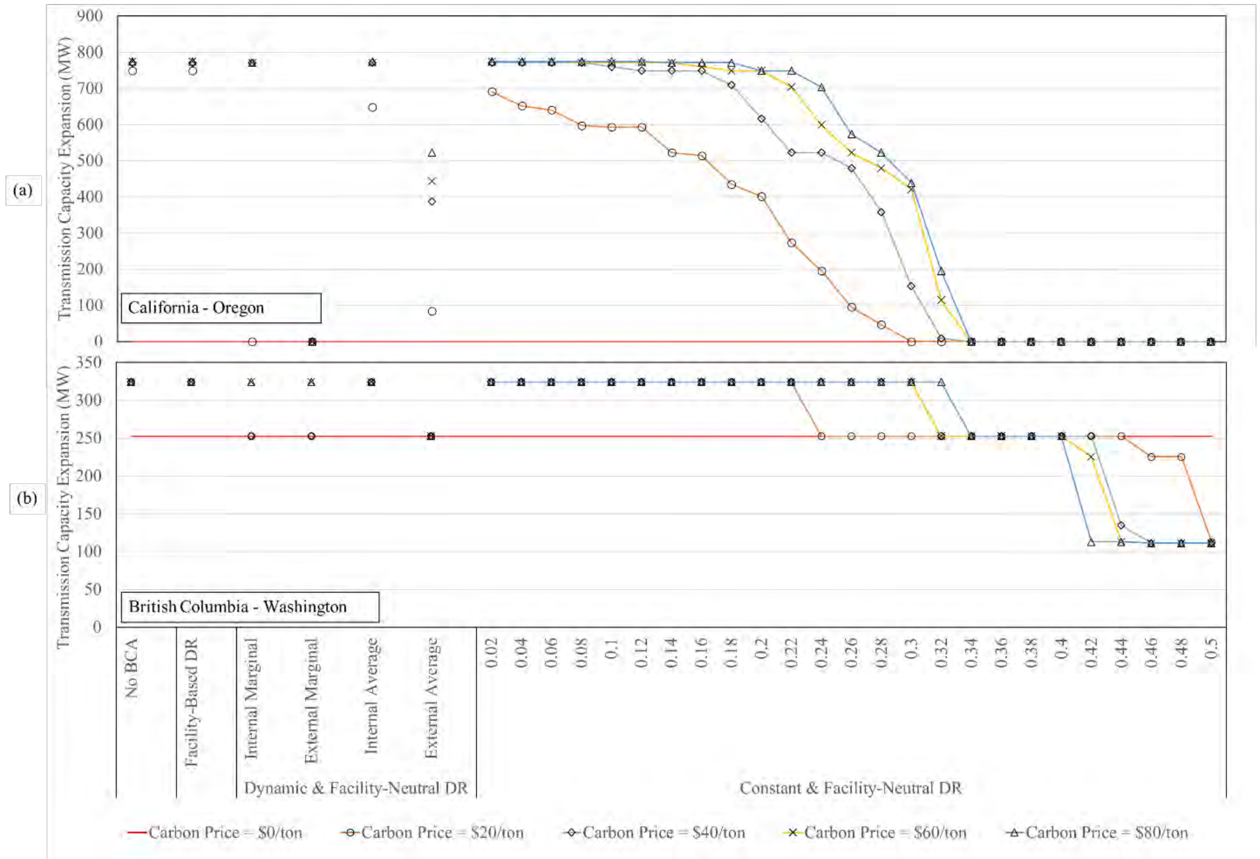

Fig. 10. Transmission capacity expansion of the California-Oregon corridor (a) and British Columbia-Washington corridor (b) under alternative DR scheme/carbon price combinations, year 2034.

Although only imports flowing into California are subject to BCA, the consequent discouragement of transmission expansion can also occur at non-California boundaries. For example, transmission expansion between British Columbia and Washington decreases from approximately 350 MW to 100 MW as BCA becomes more effective.

5.5 Economic Efficiency

In the illustrative results in Section 2, we show that an effective BCA can be designed to simultaneously lower the resource cost and the emissions compared to the no BCA case. Here in this section, we show the comprehensive results in the complex system and confirm our observations. We show the economic efficiency of different carbon pricing and BCA schemes by plotting trade-offs between cost (either WECC-wide resource cost or cost to California consumers) against WECC-wide total emissions (Fig. 11). First, we compare alternative BCA policies, identifying some that are Pareto efficient relative to others that are instead worse in both cost and emissions. We note cases in which Californians have an incentive to adopt a BCA policy that is inferior from a WECC-wide cost and emissions perspective, but is efficient considering only payments by California consumers. Second, we compare California-only carbon pricing with WECC-wide carbon pricing, and confirm that unilateral action by one jurisdiction within a larger regional power market results in cost-ineffective emissions reductions compared to a region-wide policy.

The WECC-wide resource cost is the sum of generation, transmission expansion, and operation costs, deducting RPS penalties as well as carbon payments, which are transfer payments from generators or LSEs to governments and, ultimately, taxpayers. Cost to California consumers is quantified by dividing the total annual California LSE payment (in $) by the total energy load (in MWh), with the LSE payment adjusted by reimbursements of the payment received by the California government or California ISO on behalf of consumers. These reimbursed payments include economic rents due to carbon payments (to the California Air Resources Board) and congestion rents on the California grid (defined as the within-California transmission congestion payments plus half the transmission congestion payments for interties between California and its neighbors).

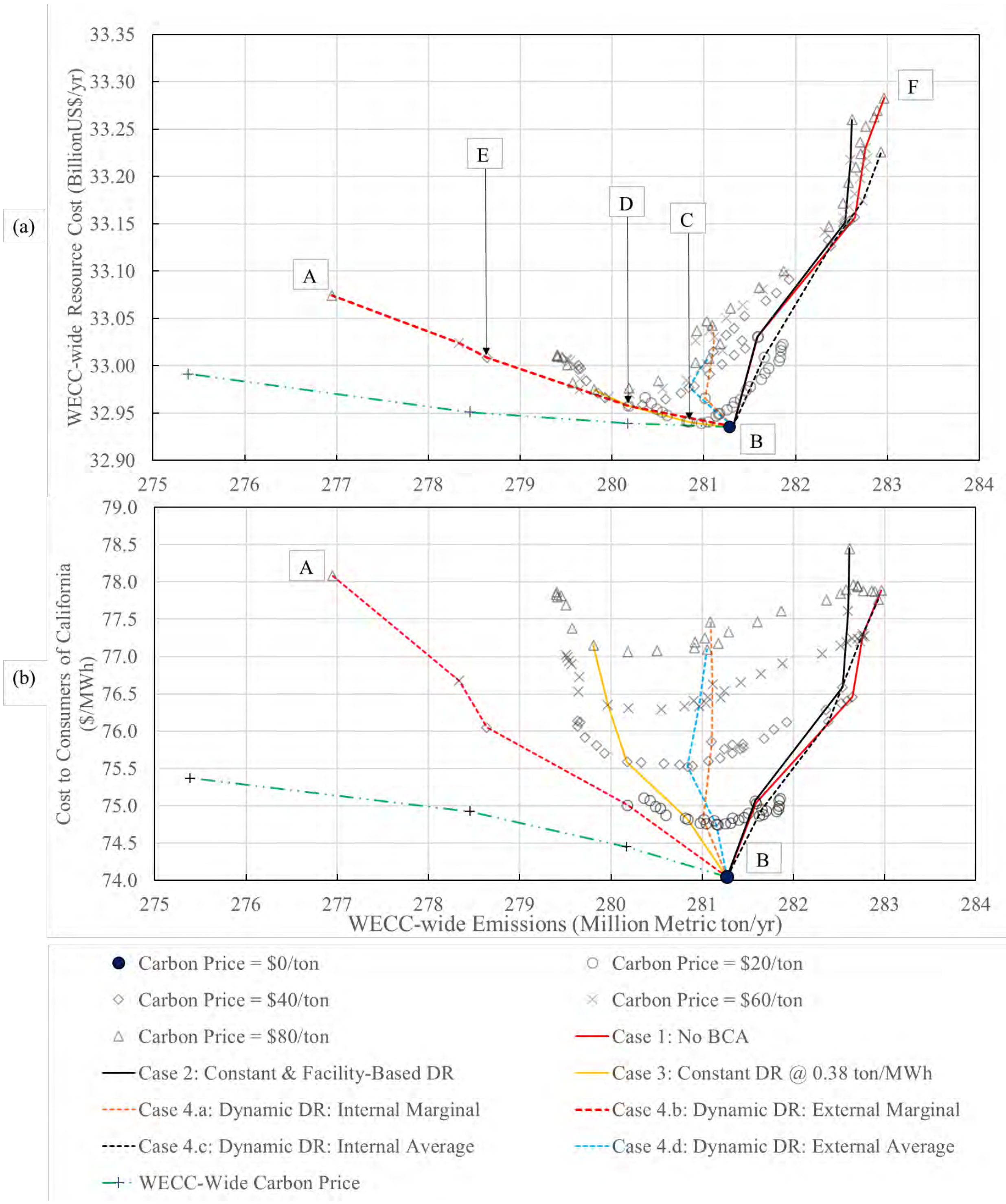

Fig. 11. Trade-offs between WECC resource costs (a) and the cost to California consumers (b), against the WECC-wide emissions, comparing alternative DR scheme/California carbon price policy combinations. For some example DR schemes, with different carbon prices are connected by colored lines.

Comparison of BCA Policies under California Carbon Pricing. Fig. 11(a) shows trade-offs between WECC-wide resource costs and emissions. Among all DR settings/California carbon price policies, the dominant (Pareto optimal) policies are located between points A and B. These include dynamic DR schemes based on external marginal emission rates (Case 4.b), along with some solutions with high constant DR (Case 3). The Pareto dominant alternatives show that by adopting a BCA with DRs based on Case 4.b, by increasing the CO_2e price in California from \$0/ton to \$80/ton, approximately 4.3 MT/yr of emissions can be avoided at a WECC-wide incremental cost of 140 \$M/yr (Fig. 11(a)), or just over \$30/ton. The cost to California ratepayers of that emission decrease is \$4.0/MWh (Fig. 11(b)), or \$1370 M/yr (based on California's annual power consumption of 343.7 TWh in the year 2034). Thus, other market participants (generators and ROW consumers) are made better off by 1370-140 = 1230 \$M/yr by such a policy change, mainly because of power rate hikes induced by the increase in the marginal cost of supply to California. (Note that some of that 1230 \$/M/yr is earned by regulated California utility generation, which would then ultimately be returned to consumers in the form of lower regulated rates, which is not considered here.)

Meanwhile, Fig. 11(a) show that other DR solutions are dominated by the dynamic DR (Case 4.b external marginal) and some of the high constant DR solutions, as they lie to the northeast of the dominant points. For instance, Point F (Case 1, no DR, \$80/ton carbon price in California) costs \$340M more in WECC-wide costs while increasing emissions by 1.69 MT/yr. Facility-based DR and internal marginal emissions-based DR perform nearly as badly under that high carbon price.

By selecting a Pareto efficient DR scheme, the model indicates that WECC system generation and transmission investments and operations would be cleaner and less costly. However, a caveat should be noted: a Pareto improvement is not ensured just by changing the DR policy; both DR and carbon prices need to be adjusted, in general. For example, if the carbon price is \$20/ton (circles in Fig. 11), moving the solution from a constant DR of 0.38 tons/MWh (Point C, Emissions = 280.84 MT/yr, Resource cost = 32.94 \$B/yr, Fig. 11 (a)) to a dynamic DR based on the external marginal emission rate (Point D, Emissions = 280.18 MT/yr, Resource cost = \$32.96 \$B/yr) indeed cuts system-wide emission (by 0.66 Mtons/year), but the WECC resource cost is higher (20 \$M/year). Meanwhile, inefficient DF solutions, such as no BCA, facility-based DR, and low fixed DR values not only make the system emit more but also increase costs. Their efficiency worsens when the carbon price becomes higher.

As mentioned in Section 1, another design feature of BCA schemes is whether power exports from a regulated jurisdiction will have their emission payments rebated. Although not discussed here, our previous analysis (Xu, 2020) shows that rebating that cost to exports of power from California can also provide efficiency gains compared to the one-way (imports only) BCA based on facility-based DR. However, the solutions are still inferior in terms of cost and emissionsto the Pareto frontier solutions identified in Fig. 11(a). For example, when carbon price = $40/ton, a BCA scheme that rebates exports as well as charges imports with the facility-based DR results in a WECC resource cost at 33.01 $B/yr and total emissions at 280.93 MT/yr, using the same database in this paper. Compared to Point F in Fig. 11(a) (facility-based BCA, imports only), the emissions are lower by 1.73 MT/yr, and the WECC-wide cost is 150 $M/yr less, which is an efficiency gain of rebating allowances. However, at the same cost at 33.01 $B/yr, one-way BCA with dynamic DR based on external marginal emission rate (Case 4.b) results in even lower emissions (278.64 MT/yr, Point E in Fig. 11(a)).

Fig. 11(b) shows the trade-off between costs to California consumers and WECC-wide emissions. In general, California consumers would pay more with a higher carbon price. For example, without a carbon price, the model simulation shows that California consumers would buy electricity at $74.00/MWh in 2034; when the carbon price is $20/ton, the cost would increase to $74.75/MWh to $75.11/MWh, depending on the DR. However, the trade-offs also show that the curve formed by a dynamic DR (DR scheme Case 4.b based external marginal emission rate) in combination with different carbon prices still dominates other solutions, just as they do for WECC-wide cost. This again indicates a promising efficiency gain relative to current policy (DR scheme Case 2, facility-based DR). Furthermore, within each price range, the cost of this dynamic DR to California consumers can sometimes be lower than the no BCA case. That is, given a carbon price, switching from no BCA (Case 1, as well as from Case 2, facility-based DR) can reduce the system-wide emissions, while also saving money for California consumers.

Finally, constant DR schemes that minimize the relative leakage (i.e., fixed DR of 0.38 tons/MWh, which Section 5.3 identifies as having the lowest leakage rate) lie on the Pareto frontier when considering WECC-cost vs. WECC emission trade-offs, but are clearly dominated by other solutions in the trade-off of the cost-to-CA-consumers vs. WECC-emissions. This suggest that solutions that are best at avoiding leakage systematically shift costs to California consumers from other market participants.

Efficiency of California versus WECC-Wide Carbon Pricing. Although the dynamic DR based on the external marginal rate provides an economic efficiency gain for unilateral carbon pricing relative to other DR policies, this BCA-augmented unilateral carbon price in California clearly remains far less efficient than the WECC-wide carbon pricing. For perspective, Fig. 11 shows four additional points (connected by a green dashed line) that represent efficient benchmark policies for the entire WECC region: a WECC-wide carbon price/tax applied at \$0/ton (for British Columbia, this WECC-wide carbon price is on top of its existing carbon tax), \$5/ton, \$10/ton, and \$15/ton. The results indicate that California can unilaterally motivate some changes in west-wide emissions, as the red frontier shows—but the cost of doing so per ton of emissions reduction is much greater than the cost of an efficient west-wide policy. For instance in Fig. 11(a), the slopes from the no carbon price case (B) to points along the red frontier (California carbon pricing only with external marginal emissions-based DR, with carbon prices of \$20/ton to \$80/ton) are \$20/ton, \$27.7/ton, \$30.1/ton, and \$32/ton of reduction, respectively. These costs are approximately three to five times as high as the incremental costs of \$3.20/ton, \$5.44/ton, and \$9.44/ton for the cases of WECC-wide carbon prices of \$5/ton, \$10/ton, and \$15/ton. Using a WECC-wide efficient policy to achieve the same reductions as the most efficient California-only policy would cost only about one-quarter as much. California ratepayers would also pay much less (Fig. 11(b)).

6 Conclusions and Policy Implications

Carbon pricing is widely regarded as the most cost-efficient and theoretically attractive approach to cut carbon dioxide emissions from the power sector. However, carbon leakage, owing to the homogeneity of electricity and the limited geographical coverage of carbon pricing when implemented by a local jurisdiction, can substantially weaken the effectiveness of local carbon pricing when the jurisdiction is embedded in a larger regional power market. If implemented carefully with effective policies to assign emissions to imports, border carbon adjustments can be a remedy that mitigates carbon leakage and improves the economic efficiency of local carbon pricing. BCA policies based on ineffective deemed emission rates for imports, however, can provide little incentive to reduce emissions outside the regulated jurisdiction, and can even worsen costs and emissions. For example, if the regulator estimates the imported emissions on the basis of the source of the import contract, contract shuffling among the rest of the region's power plants can easily reduce the deemed imported emissions without substantially changing the dispatch and thus emissions of those plants. Thus, the performance of BCA in power systems is greatly undermined, and new ways to set the DR for electricity imports are warranted.

This paper explores the potential cost and emission impacts of different BCA schemes that could possibly be implemented in the California carbon pricing system, a local carbon pricing system in the Western Electricity Coordinating Council of North America. Our simulation shows that the impacts of California carbon pricing and potential BCAs on the WECC have multiple aspects. Based on estimates from a WECC-wide generation and transmission investment and operations model for the year 2034, we find that if there is a California carbon price but no BCA, then California emissions decrease. However, WECC-wide emissions increase in compensation, perhaps by even more than the California reduction. The emission leakage is largely due to a shift from gas-fired power from existing gas power plants of California to those in the rest of the WECC. More incentives for interstate transmission development will result because of the California carbon price, and this effect is not limited to the California boundary. Under the assumptions of our case study, local carbon pricing would raise both the cost to California consumers and the cost to the WECC in total without lowering emissions, and, consequently, California carbon pricing without BCA is ineffective and costly.

Meanwhile, implementing BCA with a facility-based DR scheme that is the basis of the actual California BCA system is only marginally better, as indicated both by our schematic model in Section 2 and the detailed transmission-generation expansion model in Sections 3-5. The efficiency improvement is negligible because of contract shuffling, similar to other findings in the literature (Bushnell et al., 2014). We emphasize that our conclusions concerning the low effectiveness of facility-based DR schemes are limited to the electricity sector, and depend on specific assumptions that are plausible in the electricity sector but not in others, e.g., inelastic demand and a subnational market. Consequently, our conclusions may be more or less applicable to other sectors, e.g., the steel sector (Mehling and Ritz, 2020), depending on the ease of shuffling. However, a constant and facility-neutral DR can bring gas power back to California and decrease the tonnage of emissions leakage. A high facility-neutral DR also provides some efficiency gains by simultaneously lowering the WECC-wide cost and emissions without making California consumers pay more. Effective BCAs also lead to fewer inefficient incentives to build interstate transmission lines. In reality, source specification of the imports to California will not always be possible, and a high DR of 0.428 tons/MWh will be applied to the imports. For example, in 2017, among all imported electricity (around 94 TWh), 20% of imports are unspecified (CARB, 2019a). Thus, we conclude that the real performance of the present California BCA should be intermediate between our solutions of constant DR = 0.44 tons/MWh (which is relatively efficient) and facility-based DR (which we project increases costs and emissions).

The most notable policy conclusion is that, among all investigated DRs, the dynamic DR set by external marginal emission rates provides the greatest efficiency gain, and its solutions are Pareto efficient relative to other DR policies. It is also the only BCA scheme that decreases coal power production in the rest of the WECC, because it sets a high DR at the same times that non-California marginal units are coal powered. However, other solutions (not shown) indicate that these changes in generation mix are very modest relative, for instance, what would result from a carbon price applied to the entire WECC.

As the results suggest, switching from the current facility-based BCA to dynamically setting a facility-neutral DR based on marginal units outside of California appears to be a reasonable and beneficial move for California. However, estimating marginal emissions requires some effort and is error-prone, especially because the information on the marginal unit is usually *ex post*, i.e., which unit is marginal is known only after the system dispatch. If the DR is updated with the marginal information and market participants are given another chance to bid and re-dispatch, the marginal units may well change. We have observed this phenomenon in our results. We also acknowledge that actually determining marginal emissions rates (or similarly, marginal emission displacement rate of renewable energy) is difficult, especially where unit commitment and ramp-limitations have a significant impact on operations (Chen et al., 2008; Chyong et al., 2019; Thomson et al., 2017). Nevertheless, our findings still suggest that the estimation of the marginal emission rate does not need to be exact to provide economic efficiency gain. We also suggest that consideration be given to rebating emissions allowances to exports of power from California, which may under some conditions lower costs and regional emissions both, compared to facility-based BCA that only charges imports. However, elsewhere we have found that the efficiency gains from doing so are smaller than the gains obtained by implementing a BCA policy with facility-neutral deemed rates based on marginal external units (Xu, 2020).

Finally, and notably, even if augmented by the most efficient DR scheme, the unilateral carbon price of California remains far less efficient than a hypothetical WECC-wide carbon pricing policy. Thus, together with enhancing California's current BCA scheme, we also suggest expanding California's carbon pricing regimes through collaboration with other states, such as Oregon and Washington, as a better approach.

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