A Zonal Approach to Implementing Non-Priced GHG-Reduction Programs in a Zonal Day Ahead Market.

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The GHG Subgroup consists of selected commissioners and staff from Washington, Oregon, California, Nevada, Colorado and New Mexico. These states' utility commissions have jointly agreed to collaborate and assist in developing multi-state solutions for their respective clean energy programs.

The GHG Subgroup commissioners believe that the proposal presented in this white paper should be considered by the Markets+ GHG Task Force as one possible solution for assisting the jurisdictional utilities of the member commissions in meeting their obligations under their respective state's environmental laws while participating in the day-ahead market. However, the commissioners caution that support for considering the paper in the Markets+ GHG Task Force is not an implicit endorsement of the Zonal approach. Additionally, each state reserves the opportunity to review of any solution proposed in a tariff for compliance with that state's law and via the appropriate agency's decision-making process.

Introduction

This paper presents a technical approach to the implementation of non-priced GHG reduction programs. These programs can also be called emission constraint programs or cap programs. In this paper we will refer to them simply as GHG-reduction programs, the non-priced aspect being understood. In the Western Interconnection, GHG-reduction programs are found in Oregon, Nevada, Colorado, and New Mexico[1]. Cap-and-trade programs found in California and Washington, however, are in a different category since those are *priced* programs: a price for a CO_2 allowance, equal to one metric ton (mton) of CO_2e, is established through an open auction. The GHG-reduction programs have no explicit price set for CO_2, instead they establish GHG reduction mandates for utilities through statute.

Except for New Mexico[2], the programs are generally framed as requiring the subject utility to limit the aggregate CO_2 emissions of its generation portfolio serving its load in year (Y), measured in metric tons(mtons), to an amount specified by a percentage reduction (X_Y) relative to a based year (B), i.e., the maximum emissions allowed to be emitted by the utility in serving its load in year Y is $B*(1 – X_Y)$ mtons. The percentages increase over time, eventually reaching 100%, i.e., zero emissions. Compliance periods for these programs extends over longer periods, generally one to three years.

For example, Oregon's bill requires subject utilities to reduce their portfolio emissions by 80% by 2030, 90% by 2035, and 100% by 2040 relative to a baseline equal to the average for years 2010-2012. Colorado's requirement for subject utilities is 80% reduction by 2030 and a goal of 100% by 2050 relative to a 2005 baseline.

In contrast to a cap-and-trade program, GHG-reduction programs place compliance on the load serving-entity (LSE). This means a generator based in a state like Oregon that serves load outside Oregon would not be covered under the GHG-reduction program. Cap-and-trade programs cover in-state generators even if they serve out-of-state.

GHG reduction programs differ between the states in terms of the cadence of reductions, the baseline levels, the exemptions and carve-outs allowed to utilities and which utilities are subject to the program. Therefore, it would be impractical to try to incorporate each state's different program structure into market design. Instead, this paper proposes a relatively straightforward mechanism that allows each entity subject to a GHG-reduction program to manage its own portfolio average emissions within the market. The approach places the responsibility for meeting its program requirements on the utility, not the market operator.

[1] Washington has a non-priced clean energy program (CETA) which is of a significantly different form than the non-priced GHG programs discussed in this paper. Compliance in CETA would not necessarily be met through the proposal presented here.

[2] New Mexico has a provision for any utility issuing a securitization order (i.e., Public Service of New Mexico) that requires the aggregate generation portfolio for load to meet an emission standard of no more than 400 lbs/mwh by 1/1/2023 and 200 lbs/mwh by 1/1/2032 (SB-489 2019, Section 10.D). Although framed as a mass-based standard, New Mexico's formulation could also be met through the technical approach described herein.

Incorporating GHG-Reduction and Cap-and-Trade Programs in Electricity Markets

There are challenges to incorporating either cap-and-trade or GHG-reduction programs into market design. The organizing principle of an electricity market is the dispatch of generating resources on a least cost basis. If the market encompasses resources that are all subject to the same environmental standards, then the situation is straightforward: resources would include the cost of environmental compliance in their energy bids and settle their compliance obligations with environmental authorities outside of the market. This is the case in both the New York ISO and the ISO New England which are covered by the Regional Greenhouse Gas Initiative. In this case, internalization of the environmental costs may increase the overall cost of energy by impacting the market clearing price when emitting resources are selected for dispatch, but it does so without discrimination as to where the resource is located or which LSE it is serving.

Complication arises when the market footprint covers sub-regions subject to a GHG-reduction or cap-and-trade program, called a GHG Zone, and sub-regions not covered – the non-GHG zone. We will briefly describe how this is proposed to be handled in the case of the California and Washington cap-and-trade programs in SPP's Markets+. This provides a necessary foundation for understanding this paper's proposal for integrating GHG-reduction programs into Markets+.

Incorporating Cap-and-Trade Programs into SPP's Markets+

California's and Washington's cap-and-trade programs require external electricity importers to submit CO_2 allowances. To do this, the concept of the First Jurisdictional Deliverer (FJD) is created which is the entity accountable to the relevant state agency for reporting imported electricity and submitting the necessary allowances. In bilateral electricity markets, the FJD would usually be the resource owner. E-tags provide the measurement and verification instrument.

In a centrally dispatched electricity market, there is no contractual pairing of originators and receivers, there is no e-tagging of (most) imports in the market. The CAISO pioneered a methodology, called the Resource Specific approach, that "deems" which resources were importers to California during the dispatch interval. It incorporates the cost of allowances into the deemed importers' market offer price so that its revenues from market dispatch are sufficient to pay for the necessary allowances. The Resource Specific approach was incorporated into the Western Energy Imbalance Market and will be incorporated into the Extended Day-Ahead Market.

The foundation of this paper is on a different approach that is proposed to be adopted in the Markets+ day-ahead and real-time market design, called the Zonal approach. The Zonal model establishes two exclusive pathways through which electricity is imported into a GHG Zone – the Specified Resource and the Unspecified Resources pathways. The intention is that imports into a GHG zone can only occur through these two paths and that a resource eligible to import through the Specified Resource pathway cannot import though the Unspecified Resources pathway. In other words, it the Specified Resource dispatches, it will be deemed to be serving the GHG zone[3].

The Specified Resource pathway designates certain resources eligible to import into the cap-and-trade zone and if dispatched will be "deemed" to be serving that zone. The Specified Resource becomes the FJD and includes its compliance cost in its energy bid. In this paper, it is assumed that a resource can be partially a Specified Resource with the remaining amount not a Specified Resource. This may be necessary to accommodate joint-owned-units (JOUs) which have multiple owners, some of which may be subject to a cap-and-trade program and some not. The relevant state authorities will be responsible for defining the exact criteria by which a resource can be designated eligible to be a Specified Resource, but the presumption is that the resource would probably have some regulatory obligation to serve one or more LSEs within the GHG zone.

The other import pathway is the Unspecified Resources pathway, through which bulk energy can be imported without identifying the individual resources as the originators of the electricity. It is still imported electricity and so must be accounted for in the cap-and-trade program. Therefore, a default GHG rate (mtons/mwh) is assigned to imports through the Unspecified Resources pathway, and the FJD for the Unspecified Resources allowances is assigned to a separate party[4]. The cost of the allowances for the Unspecified Resources pathway importation creates a GHG marginal cost which is part of the Locational Marginal Price (LMP) formation and is paid by the LSE. There is a balance of payments between LSE's payments into the market operator, and the market operator's payments out to the generators and to the FJD entity (which may be the market operator).

We turn next to GHG-reduction programs.

Incorporating GHG-reduction Programs in Electricity Markets

The Rationale for Addressing GHG-Reduction Programs

A question that arises is whether it is even necessary to incorporate a mechanism into market design which addresses the GHG-reduction programs. Unlike cap-and-trade programs, compliance is spread over a longer term and is not necessary over short intervals. Compliance could be left to the Integrated Resource Planning (IRP) processes of the states. Indeed, these programs were originally designed at a time when the utility met its resource adequacy through a combination of owned generation and bilateral contracts, all of which are medium-term (months), long-term (years) or very-long term (decades) resource decisions which the IRP

[3] The design of the Zonal approach is ongoing as of the publication of this paper. Statements about what the Zonal model is intended to do represent our best current understanding. In particular, the final as-yet-undefined criteria around what constitutes a Specified Resource may permit it to path-switch to the Unspecified Resources path if the optimization program determines it costs the system less to do that. That would change the dispatch numbers shown in the examples at the end of the paper, but would not change the concept described in this paper.

[4] The FJD for the Unspecified Resources is still being defined for the Zonal approach, and the legality of this approach under California and Washington cap and trade laws is still under review.

process is well-suited to handling. The advent of the energy imbalance market in the western states did not change that perspective since it transacted a small portion of annual energy.

A day-ahead market changes that perspective since all energy needs would be transacted in the market. The element that changes the most for utilities subject to these GHG-reduction programs is importation and exportation of electricity to/from their balancing area. For subject utilities that join a day-ahead market, it is assumed that hourly/daily imports through the market would comprise a significant portion of their annual electricity consumption, yet those utilities would have no control over or even knowledge about the emissions profile of those imports. Assessing all imports at a predetermined average rate, which has been suggested, is believed would soon exceed a level which would allow the subject utility to meet its annual goals without making accelerated and unnecessary changes to its own portfolio of contracts and owned-generation. This seems particularly to be the case in parts of the mountain-west and the desert-southwest. It is believed to be important to explore alternatives that could allow the utilities subject to GHG-reduction programs to better control emissions entering and exiting through the market at least possible cost.

A Few Basics of Optimized Dispatch in Electric Markets

The deeper technical details involved in dispatch optimization algorithms described here will be found in the appendix. However, a few high-level concepts are necessary for this discussion. A market dispatch algorithm is a very large *linear optimization* program. This program selects the dispatch of each generator offered into the market in such a way that the total system bid cost, called the *objective function*, is minimized. It must do this subject to certain limitations called *constraints*: it cannot dispatch a generator at more than the generator's maximum offered quantity (called the upper economic limit), it cannot exceed transmission limits, it must exactly balance load and generation within the market. This last constraint is called the Power Balance constraint. There can be many more constraints.

Each constraint has associated with it a *shadow price* which is the change in the total system bid cost if the constraint were tightened (i.e., more constrained) by one more unit. In particular, the Power Balance constraint has a shadow price which is called the system marginal energy price (SMEC) and is a component of the Locational Marginal Price. The transmission constraint shadow price is another component, called the congestion marginal cost.

With this brief background on the Zonal approach and electricity market dispatch optimization, we discuss the approach for incorporating GHG-reduction programs into cost-based dispatch by introducing some additional requirements on the GHG zone scheduling entity in the front end of the dispatch process, and some additional constraints in the dispatch algorithm. The principal new constraint will be called the *emission constraint* and will cause the dispatch solution to seek the lowest cost solution subject to a maximum emissions quantity (mtons) for the GHG-reduction zone. This value, the maximum emissions quantity, is an input to the dispatch process. The shadow price of the emission constraint tells us the marginal cost of carbon ($/mton) for the GHG zone in that interval. In other words, rather than setting a marginal price for CO_2 as an input to the dispatch process as is done for the cap-and-trade case, in the case of the GHG-reduction program, the dispatch process produces the marginal price of CO_2 as an output. Over many intervals, it would indicate the costs associated with GHG-reduction programs which would be valuable information for policy-makers and economist in how to best deploy resources to meet their programs.

The Emission Constraint

The objective function, variables, and constraints for the dispatch optimization program would be those of the Zonal approach, but with the addition of the Emission Constraint and some additional constraints on the transmission between zones. The purpose of the Emissions Constraint is to limit the total emissions of the generation dispatched to meet load in the GHG Zone to no more than a maximum tonnage of CO_2 established prior to dispatch. The emissions constraint is specific to a GHG Zone. If there is more than one GHG Zone in the market, there will be separate emission constraints for each such GHG Zone. This is because each utility subject to a GHG-reduction program will have different targets and strategies, and therefore must have the ability to set their individual maximum emissions quantity. The utility also has the responsibility to set the default GHG rate for imports through the Unspecified Resources path. Otherwise, the emission constraints work identically for each GHG zone.

The plain language description of the Emissions Constraint is:

> Emissions due to the dispatch of GHG reduction zone **internal generation**
>
> *PLUS* emissions due to the dispatch of **Specified Resources** imported to the GHG Zone
>
> *PLUS* emissions due to dispatch of the **Unspecified Resources Path** imported to the GHG Zone
>
> *MINUS* emissions due to **exports** out of the GHG Zone
>
> *must be less than or equal to*
>
> the **maximum emissions quantity** set for the GHG Zone

Details of the Emissions Constraint

- **Maximum specification:** The **maximum emissions quantity** is metric tons of CO_2 for the dispatch interval. However, the scheduling entity[5] could specify it as either a rate

[5] Each load and resource owner has a scheduling entity which is responsible for submitting the load forecast and resource bids for which it is responsible. For example, a BAA with both load and resources would normally act as its own scheduling entity. A non-BAA resource without load or an LSE without resources would normally use the BAA in which it is physically located as its scheduling entity.

(mtons/mwh) or a mass (mtons). Since the scheduling entity knows the load forecast, converting between a rate and a mass is straightforward:

rate (mtons/mwh) * load (mwh) = mass (mtons).

The examples discussed in this paper use a rate, called the maximum emissions rate.

- **The emissions constraint operates on the portfolio not on resources**: The GHG-reduction programs are not enforced on each individual resource but rather on the sum of all resources used to meet the load. Therefore, the maximum emissions limit specified by the scheduling entity will limit emissions on the full dispatched cohort of resources used to meet its load, including internal generation and imports from outside the GHG zone and excluding exports from the GHG subregion. This allows the dispatch algorithm to deploy resources with an emissions rate greater than the maximum emissions rate but which could be offset by lower emitting resources.

- **Exports:** The exclusion of exported electricity from the emissions calculation is important in the context of JOUs that are operated by a subject utility, but which have other owners not subject to the GHG-reduction program. Compliance in a GHG-reduction program is based on the LSE and, therefore, we subtract emissions associated with generation produced within the GHG zone of a subject utility, but which is not serving the load of the GHG subregion.

Scheduling Entity Responsibilities

Under the Zonal approach with emissions constraint added, there would be certain upfront responsibilities of the scheduling entity for the utility subject to a GHG-reduction program when submitting resource bids to the market operator.

1. **The maximum emissions rate**: Establishing the correct rate to meet the GHG reduction program requirements is the responsibility of the scheduling entity not the market operator. Even if two utilities are subject to the same GHG reduction program goals, their specific mass-based and rate-based goals will be different and they may have different strategies for meeting their overall compliance. A utility may decide to lower its maximum emissions rate (mtons/mwh) during summer peak hours, while another utility may want to increase its maximum emissions rate during summer peak hours and utilize a lower maximum emissions rate in other hours so that the annual emissions budget is achieved. It may not want to enforce the emissions constraint at all in some dispatch intervals (e.g., setting a maximum emissions limit rate to 999,999 mtons/mwh). The scheduling entity has the responsibility to set the emissions targets for its LSE in each dispatch interval. It would be anticipated that the maximum emissions rate would be set according to a pre-established schedule based on seasonal and peak/non-peak characteristics of the market.

2. **Resource sufficiency**: Introducing the emissions constraint could raise the possibility of infeasibility of the dispatch solution if there are not enough offers in the market to meet

the emission constraint. To avoid this problem, the utility subject to the GHG-reduction program must satisfy an emissions resource sufficiency requirement in each dispatch interval in which the maximum emissions rate is invoked. This emissions resource sufficiency test requires the utility offer the market a portfolio of resources that could meet the maximum emissions rate absent market operation, using internal and Specified Resources generation.

3. **Specified resources:** Resources that are eligible to use the Specified Resource pathway must submit the resource's specific emission rate (mtons/mwh) with its energy bid. If a resource is partially designated as a Specified Resource, with the remaining maximum bid amount being unspecified, then the upper limit of the portion designated as a Specified Resource must by entered in the bid.

4. **Unspecified resources**: In the cap-and-trade GHG zone, the Zonal approach sets a default emissions rate for imports through the Unspecified Resources path, which is multiplied by the auction-determined allowance price to create the cost ($/mwh) of importing through the Unspecified Resources path. Likewise, in the emission constraint GHG zone, the Zonal approach requires that a default emission rate be specified by the scheduling entity for imports through the Unspecified Resources path in order to calculate the emissions associated with the Unspecified Resources path. There is no dollar-cost to importing through the unspecified resources path in the emission constraint aspect of Zonal, so the Unspecified Resources path is represented in the objective function by a dummy variable, i.e., the cost of using the unspecified resources path to the GHG zone is set at $0.001/mwh.

5. **Exports.** We must be able to identify resources that are exporting out of a GHG zone and have a specific emissions rate for that generator. This means that the scheduling entity must designate the resources eligible to export out of the GHG zone, the maximum amount of the offer that is available for export and the specific emissions rate for the designated export. For example, if there is a JOU within the GHG Zone, the scheduling entity would identify in each dispatch interval, the amount of production from the JOU that is designated as export and the emissions rate associated with the export production. If the export is destined for importation into another GHG-reduction zone or a cap-and-trade zone, then the scheduling entity of the importing zone must designate it as a Specified Resource. This is analogous to e-tagging in the market.

Price Formation and Settlement[6]

The Power Balance constraint for the entire market footprint sets the system marginal energy cost (SMEC)[7]. Each GHG zone, whether a cap-and-trade zone or a GHG-reduction zone, would have a "Load Sufficiency" constraint which requires the load in those subregions be met. The

[6] In this section and all examples, the "reference bus" is the non-GHG zone, that is, the SMEC is set in the non-GHG zone and GHG marginal costs are never negative.
[7] This is the understanding based on the Markets+ GHG Task Force meeting of 6/1/23. CAISO EIM and presumably EDAM applies the Power Balance constraint to each individual BAA in the market.

"Load Sufficiency" constraints[8] establish a GHG marginal cost for each GHG zone separately[9]. Our examples assume there is no transmission constraint, so the LMP for the non-GHG zone is just the SMEC, and the LMP for each GHG Zone is the sum of the SMEC and the GHG marginal cost for that zone.

Settlement is relatively straight forward:

1. All generators are paid the SMEC.
2. Generators internal to a GHG zone are paid the GHG marginal cost for that zone. Generators, or portions thereof, that are Specified Resources to a GHG zone are paid the GHG marginal cost of that zone.
3. In the case of a cap-and-trade zone, the revenue collected from the Unspecified Resources path (mwh x default GHG emissions rate x allowance price) is paid to the entity acting as the FJD for the Unspecified Resources path and is used to purchase the necessary allowances.
4. In the case of the GHG-reduction zone, revenue is also created by the Unspecified Resources path (mwh x GHG marginal cost).
5. Each LSE will pay the LMP for the zone it is in times the amount of load served.

In step 4, revenue is created via the Unspecified Resources path due to the GHG marginal cost created by the load sufficiency constraint. This revenue is a direct result of the GHG-reduction program of the state, and so presumably would be distributed through a state-sanctioned method, which might include:

1. Pro-rata distribution to the generators that were eligible to contribute to the Unspecified Resources, i.e., generators not in the GHG zone and generators not Specified Resources to the GHG zone or any other GHG zone.

2. A credit back to the LSE subject to the specific GHG-reduction program.

3. Payment into a state-sanctioned fund for investment pursuant to state policies.

FERC Approval

Adapting the Zonal approach to cap-and-trade or GHG-reduction programs would be new design elements for FERC to consider. With respect to the emission constraint adaptation, the following arguments can be made in favor of approval.

1. Market design incorporates many constraints that are non-cost based: transmission, UEL, etc. Constraining on emissions is another instance, analogous to transmission constraints. Moreover, the shadow prices of each constraint reveal import, useful data about the cost

[8] See Appendix I for a full description of the constraints

[9] This is different from the carbon marginal cost which is the shadow cost of the emissions constraint. The carbon marginal cost is dollars per mton, and the GHG marginal cost is dollars per mwh. The two are related, as the examples show.

of the restrictions which can be used by policy-makers in achieving policy goals at least cost.

2. FERC has already approved the inclusion of a legally-binding state-mandated environmental requirement in market price formation when it approved CAISO's Resource Specific approach in the WEIM.

3. The shadow price of the Emission Constraint is a market-based price signal that is incorporated into the GHG zone's LMP. This price signal (the GHG marginal price) provides a monetary incentive for cleaner energy importation into the zone, just as it does in the cap-and-trade case.

4. The emission constraint approach described here allows utilities subject to a GHG-reduction program to participate in an electricity market, and meet their statutory obligations, at least dispatch cost. If another dispatch solution offered a lower cost and met the emissions criteria set by the utility, it would have been selected in the emissions constraint Zonal solution.

5. The ability of the utility to set its own maximum emissions rate might raise concerns about market manipulation. That could be addressed, for example, by requiring the subject utility to establish a minimum emission target periodically below which the utility could not set its maximum emissions rate. Setting the minimum emission target for a compliance period could be a state utility commission process using the GHG reduction program targets to guide the process.

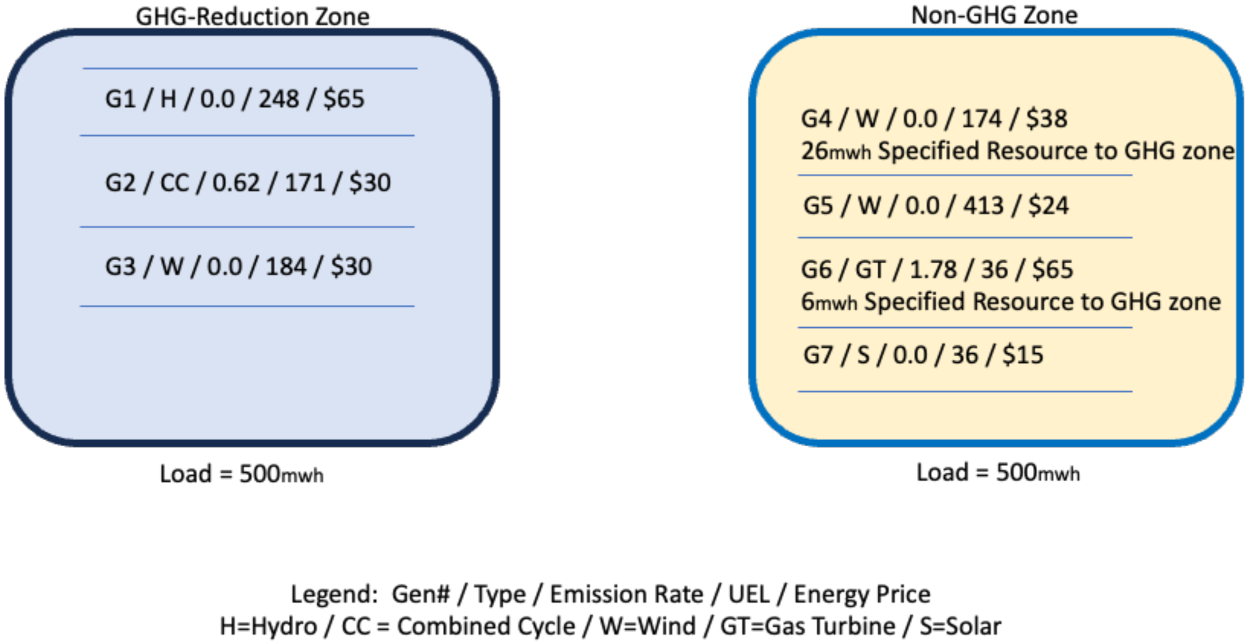
6. In the absence of a mechanism by which utilities subject to GHG-reduction programs can manage the emissions of their generation portfolio to meet load, those utilities would likely either (a) not join the market, (b) leave the market eventually, or (c) increasingly rely on self-scheduling of their owned and contracted resource, eroding the benefit from being a market participant.

Example 1. A Single GHG-Reduction Zone

This example assumes there is only a single GHG-reduction zone and the non-GHG zone. Each zone has a 500 mwh load. The generators' maximum offers, prices and emission rates are shown in Figure 1.

A maximum emissions limit rate of 0.2 mtons/mwh is set for the GHG-reduction zone. This equates to 100 mtons. The default emissions rate for Unspecified Resources being imported into A is set at 0.5 mtons/mwh. It is straightforward to check that the market footprint meets the resource sufficiency test, i.e., has offers of over 1000 mwh, and the GHG-reduction zone meets the emissions resource sufficiency test. Generators G4 and G6 have Specified Resource offers of 26 and 6 mwhs respectively. The remaining 148 mwh from G4 and 30 mwh from G6 could meet load in the non-GHG zone or be exported through the Unspecified Resources pathway to the GHG-Reduction zone.

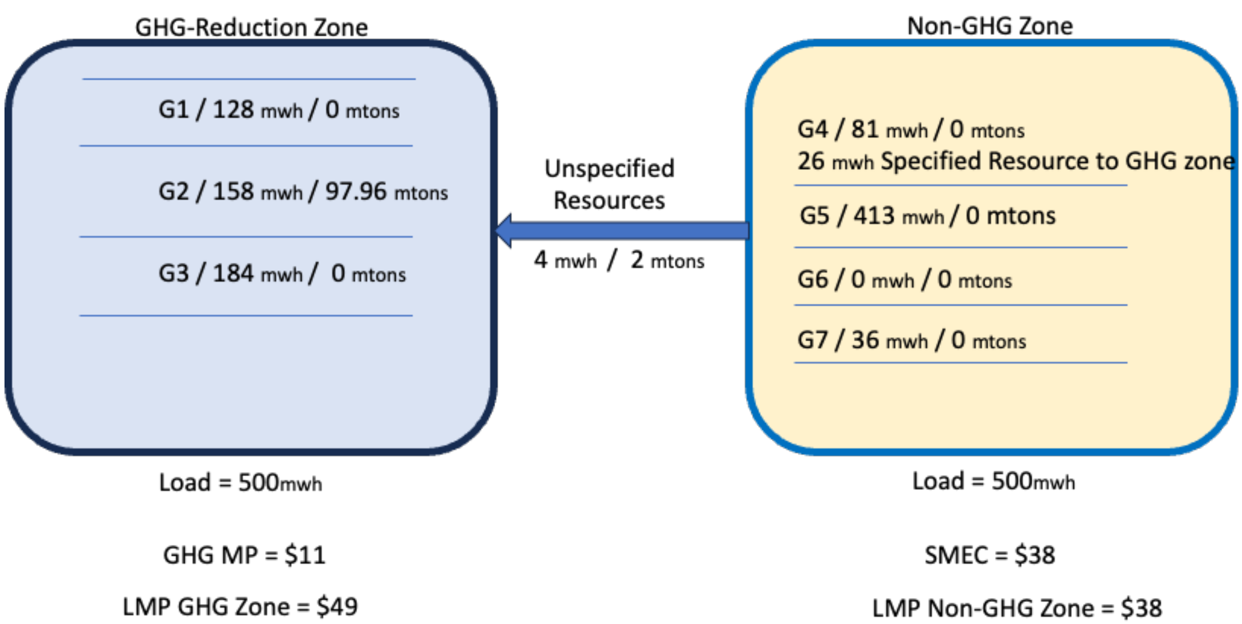
Figure 1



Scenario: PEVA

The dispatch results are shown in Figure 2. The values printed on the left are the dispatched mwh and on the right the associated emissions.

Figure 2



Scenario: PEVA.

G4 dispatched 26 mwh as a Specified Resource. An additional 4 mwh was dispatched through the Unspecified Resources, but we don't know from which generators that production originated, only that it came from a combination of G5, G7 and the 55 mwh of G6 not dispatched to serve the GHG-reduction zone.

The SMEC is $38 because one more mwh of load in the system would be met by G4.

The emissions assigned to the GHG-reduction zone are 99.96 mtons. Even though slightly short of 100 mtons, the emission constraint is binding in this example because one more mwh of load in the GHG-reduction zone would have forced the emissions over 100 mtons.

The GHG marginal price is $11/mwh, because if we were to increase the load of the GHG zone by one mwh and simultaneously decrease the load of the non-GHG zone by one mwh, then G1 will dispatch up by 1 mwh, G2 will dispatch up by 2 mwh, and G4 will dispatch down by 3 mwh which causes the Unspecified Resources path to reduce by 2 mwh[10]. The increase to the total system bid cost of that redispatch solution is $11.

The shadow price for the emission constraint is $54/mton – the carbon marginal cost. This represents a "proxy" value for a CO_2 allowance cost. We can see this, for if we decrease the maximum emissions tonnage by one mton to 99 mtons the dispatch will change by increasing the dispatch of G1 by 2 mwh and decreasing the dispatch of G4 by 2 mwh. That raises the total system dispatch cost by $54. We can also see this by noting that $54/mton times the emissions maximum rate of 0.2 mtons/mwh is very nearly equal to the GHG marginal price of $11/mwh[11].

Tables 1-A and 1-B below show how revenues and payments would be settled. Note the payment of $44 from the Unspecified Resources, which must be distributed per state-sanctioned policy.

[10] To determine the GHG marginal price, we have simultaneously increased load in the GHG zone by one mwh and decreased it by one mwh in the non-GHG zone so that we can isolate the impact of the GHG restrictions only. If we had not decreased the GHG zone by one mwh, the resulting shadow price would have included the cost of the increase in total energy in the system.

[11] It would be exactly equal if we allowed factional megawatt-hours in the dispatch solution.

Table 1-A

Generator	Dispatch	SMEC	Energy Payment	Internal & Specified Resource	GHG MP	GHG Payment	Total Payment
G1	128	$ 38	$ 4,864	128	$ 11	$ 1,408	$ 6,272
G2	158	$ 38	$ 6,004	158	$ 11	$ 1,738	$ 7,742
G3	184	$ 38	$ 6,992	184	$ 11	$ 2,024	$ 9,016
G4	81	$ 38	$ 3,078	26	$ 11	$ 286	$ 3,364
G5	413	$ 38	$ 15,694		$ 11	$ -	$ 15,694
G6	0	$ 38	$ -	0	$ 11	$ -	$ -
G7	36	$ 38	$ 1,368		$ 11	$ -	$ 1,368
TOTAL	1000		$ 38,000		$ 11	$ 5,456	$ 43,456
Unspecified Resources	4				$ 11		$ 44
Total Payments Out of Market Operator							**$ 43,500**

Table 1-B

Zone	Load	LMP	Payment
GHG Zone	500	$ 49	$ 24,500
Non-GHG Zo	500	$ 38	$ 19,000
Total Payments into Market Operator			$ 43,500

Example 2. A Single GHG-Reduction Zone and a Single Cap-and-Trade Zone

This more complex scenario is shown in tabular format. There are 3 zones: a cap-and-trade zone (A), a GHG-reduction zone (B), and the non-GHG (C). All three have a load of 500 mwh. The generator offers are shown in Table 2.

Table 2

GENERATOR	ZONE	TYPE	EMISSION RATE	PRICE	UEL	SPECIFIED RESOURCE TO A	SPECIFIED RESOURCE TO B	DESIGNATED FOR C
1	A	H	0.00	$ 35	246			
2	A	GT	0.63	$ 90	24			
3	A	C	0.94	$ 88	84			
4	B	H	0.00	$ 47	45	8		8
5	B	C	1.21	$ 44	96	20		
6	B	C	0.97	$ 46	258	93		
7	C	H	0.00	$ 36	211	42	69	
8	C	H	0.00	$ 28	130	21	35	
9	C	H	0.00	$ 34	355	60	120	
10	C	GT	1.65	$ 56	39	0	19	
11	C	CC	0.37	$ 34	470	56	139	

ALLOWANCE PRICE FOR A	$45	PER MTON
DEFAULT EMISSION RATE FOR A	0.5	MTON/MWH
MAXIMUM EMISSION RATE FOR B	0.3	MTONS/MWH
DEFAULT EMISSION RATE FOR B	0.65	MTONS/MWH

H=HYDRO / C = COAL / GT = GAS TURBINE / CC = COMBINED CYCLE

Scenario: JCX3

Several of the generators in zones B and C have Specified Resource offers into A and B. Generator 4 in B has 8 mwh designated as exportable to zone C. This could represent a JOU or a contract with an LSE in zone C.

The GHG allowance price in A is $45 per mton. Every generator in A or Specified Resource to A has this allowance price times its specific emission rate added to its price for dispatch. If dispatched, they are deemed to be serving A. The Unspecified Resources pathway into A has a default emission rate of 0.5 mton/mwh applied to it, so the cost is $22.50 per mwh ($45 x 0.5).

Zone B has a maximum emission rate of 0.3 mton/mwh. The aggregate emissions for dispatch for load deemed to serve zone B cannot exceed 150 mtons (0.3 x 500). The Unspecified Resources pathway into B has a default emission rate of 0.65 mton/mwh applied to it for purposes of complying with the 150-ton maximum emissions. There is no cost applied to the Unspecified Resources to B (except for $0.001).

Table 3 shows the final dispatch solution.

Table 3

GENERATOR	ZONE	TYPE	EMISSION RATE	PRICE	DISPATCH	SPECIFIED RESOURCE TO A	SPECIFIED RESOURCE TO B	DESIGNATED FOR C
1	A	H	0.00	$ 35	246			
2	A	GT	0.63	$ 90				
3	A	C	0.94	$ 88				
4	B	H	0.00	$ 47	38	8		1
5	B	C	1.21	$ 44	50			
6	B	C	0.97	$ 46				
7	C	H	0.00	$ 36	211	42	69	
8	C	H	0.00	$ 28	130	21	35	
9	C	H	0.00	$ 34	355	60	120	
10	C	GT	1.65	$ 56				
11	C	CC	0.37	$ 34	470	56	139	

Unspecified Resources to A	67

Unspecified Resources to B	58

Table 4 shows the power balances and Table 5 shows the emissions calculation for Zone B

Table 4

ZONE	INTERNAL GENERATION	SPECIFIED RESOURCES	UNSPECIFIED RESOURCES	EXPORTS	TOTAL
A	246	187	67		500
B	88	363	58	-9	500
C	1166	-542	-125	1	500

Table 5

ZONE	INTERNAL GENERATION	SPECIFIED RESOURCES	UNSPECIFIED RESOURCES	EXPORTS	TOTAL
B	60.5	51.43	37.7	0	149.63

The emissions constraint on Zone B is binding, since one more mwh from any available generator would raise it over 150 mwh.

Price Formation

The system marginal energy cost is $47. This is because if we increase load in the market by 1 mwh, Generator 4 will be dispatch up by 1 and that 1 mwh will be exported to Zone C.

To determine the GHG marginal cost for Zone A, we add 1 mwh to the load of A and lower the load of Zone C by 1 mwh. This will cause the Unspecified Resources to A to increase by 1 mwh at a cost of $22.50, which is the GHG marginal cost for Zone A. We observe that with this formulation of the Zonal objective function, the Unspecified Resources default emissions rate will (almost) always be the marginal GHG cost for Zone A.

We follow the same process to calculate the GHG marginal cost for Zone B. This will increase Generator 4 by 1 mwh at a cost of $47, which would be designated as an export to Zone C. Generator G5 would dispatch down by 1 mwh at a savings of $44, and the Unspecified Resources to B from C are increased by 2 mwh with virtually no cost incurred ($0.002). This will result is a GHG marginal cost of $3 per mwh ($47-$44) for Zone B.

The carbon marginal cost (emission constraint shadow price) is $6. If we were to decrease the emission constraint by 1 mton, this would increase Generator 4 by 2 mwh at a cost of $94, which would be designated as an export to Zone C. Generator G5 would dispatch down by 2 mwh at a savings of $88, and the Unspecified Resources to B from C are increased by 2 mwh with virtually no cost incurred ($0.002)[12].

Settlement

Settlement proceeds in the same way it did in Example 1. Each LSE pays its LMP times its load. Each generator is paid the SMEC. Each internal or Specified Resource to a GHG Zone (cap-and-trade or GHG-reduction), but not export to a non-GHG zone, is paid the GHG marginal cost for their generation serving the GHG zone. Unspecified Resource to a GHG Zone are paid the GHG marginal cost for that zone. In the case of the cap-and-trade zone (A), that amount is paid to the FJD for the Unspecified Resources to purchase allowances. In the case of the GHG-reduction zone (B) that amount is distributed per state-sanctioned guidelines, as in Example 1. Perhaps a simpler way of stating all of this is that a generator gets paid the LMP of the zone it is deemed to be serving. The exception is Unspecified Resources, which get only the GHG adder in the case of cap-and-trade, and nothing additional for the emissions constraint modification (they already got the SMEC for their generation). We leave calculation of settlement amounts to the curious reader.

Conclusion

The main argument of this paper is that proposals for western states day-ahead markets should consider modifications to address the needs of states which have adopted GHG-reduction programs, as they are doing for cap-and-trade states. Substantial modeling efforts show that the concept works and could be effective in assisting subject utilities in meeting their obligations and providing valuable data for policy-makers and economists on the true costs of those programs.

A development and implementation path that might ease concerns of too many new design elements in the market could be to move forward with the cap-and-trade Zonal approach, but with a concurrent trial period for the emissions constraint addition. A trial, potentially non-binding, for the emissions constraint addition might involve a small number of voluntary utilities subject to the GHG-reduction programs for one or a few years, so that all market participants can

[12] Linear optimization (LO) programs produce shadow prices automatically without going through the redispatch logic described in these examples, however, to do so they must allow fractional solutions. Converting them to integer solutions can cause the integer version shadow prices to diverge from the LO program calculation.

observe the interactions and outcomes of the various GHG programs in the market and become comfortable with market dynamics.

We encourage the various task forces developing both Market+ and RTO West protocols to consider the emissions constraint as a serious proposal for subject utilities.

Appendix 1. Programming Notes

This section contains details of the objective function, constants, variables, and constraints used in the 3-zone Zonal approach with Emission Constraint. Notation is in vector format.

Nomenclature

A : Cap and Trade Zone

B : GHG-reduction Zone

C : Non-GHG Zone

Indices for the **TRANFERS**, **TRANSMISSION_MAX** and **TRANSMISSION_PRICE** vectors
AB = 1
BA = 2
AC = 3
CA = 4
BC = 5
CB = 6

Indices for the **LOAD** vector
A = 1
B = 2
C = 3

Constants

N ∊ PositiveIntegers : Number of generators in the market model.
NOTE: Specified Resources to either A or B are considered separate generators

I ∊ Vectors[**N**, NonNegativeIntegers] : A constant vector in which all elements are 1.

UEL ∊ Vectors[**N**, NonNegativeIntegers] : Upper Economic Limit of the generators

ENERGY_PRICE ∊ Vectors[**N**, NonNegativeRealNumbers] : Energy bids in dollars of the generators.

EMISSION_RATE ∊ Vectors[**N**, NonNegativeRealNumbers] : Emission rate in metric tons/mwh of generators

TRANSMISSION_MAX ∊ Vectors[6, NonNegativeIntegers] : Maximum transmission mwh in the order AB, BA. AC, CA, BC, CB

TRANSMISSION_PRICE ∊ Vectors[6, NonNegativeRealNumbers] : Price per mwh for transfers in the order AB, BA, AC, CA, BC, CB. Prices are nominally set to $0.001.

A_ALLOWANCE_PRICE: Allowance price for Zone A.

A_DEFAULT_GHG_RATE: Default GHG rate in metric tons/mwh for imports into Zone A through the Unspecified Resources Path.

B_DEFAULT_GHG_RATE: Default GHG rate in metric tons/mwh for imports into Zone B through the Unspecified Resources Path.

B_EMISSION_RATE_MAX: Maximum emission rate in metric tons/mwh for the total of all generation meeting load in Zone B.

LOAD ∊ Vectors[3, PositiveIntegers] : the load of zones A, B and C in that order.

Masks

A mask is a 1 x **N** vector consisting only of 1's and 0's. Various masks are used to isolate certain elements in vector operations.

A_GENERATOR_MASK: 1 for each generator within Zone A, otherwise 0.

B_GENERATOR_MASK: 1 for each generator within Zone B, otherwise 0.

C_GENERATOR_MASK: 1 for each generator within Zone C, otherwise 0.

A_SP_RESOURCE_MASK: 1 for each Specified Resource to Zone A, otherwise 0.

B_SP_RESOURCE _MASK: 1 for each Specified Resource to Zone B, otherwise 0.

C_DES_RESOURCE _MASK: 1 for each resource in Zones A or B designated to serve Zone C, otherwise, 0.

UNSP_RESOURCE_MASK: 1 for each resource eligible to import to A or B through their respective Unspecified Resources path, otherwise 0.

Note: All generators eligible for Unspecified Resources path reside in Zone C.

For all generators, Gj in Zone C :

$(\text{UNSP\_RESOURCE\_MASK})_j = 1 - (\text{A\_SP\_RESOURCE\_MASK})_j - (\text{B\_SP\_RESOURCE\_MASK})_j$

Vector Operations

V and **W** are vectors of the same dimension : 1 x K.

V + **W**: Vector elements are added pairwise. Result is 1 x K vector.

V - **W**: Vector elements are subtracted pairwise. Result is 1 x K vector.

V × **W**: Vector elements are multiplied pairwise. Result is 1 x K vector.

Sum[V]: Vector elements are summed. Result is a single value.

V • **W**: Vector dot product = Sum[**V** × **W**]. Result is a single value.

V ⩽ **W:** Equals TRUE if every element of **V** is less than its corresponding element in **W**. Result is logical value.

Variables

DISPATCH ∊ Vectors[**N**, NonNegativeIntegers] : The dispatch solution for all generators.

A_UNSPECIFIED ∊ NonNegativeIntegers : The solution for the Unspecified Resources Path to A.

B_UNSPECIFIED ∊ NonNegativeIntegers : The solution for the Unspecified Resources Path to B.

TRANSFERS ∊ Vectors[6, NonNegativeIntegers] : The solution for the mwh transfers between in the Zones in the order of AB, BA, AC, CA, BC, CB.

Objective Function

TOTAL_SYSTEM _BID _COST = **DISPATCH** • **ENERGY_PRICE** +
A_UNSPECIFIED × **A_ALLOWANCE_PRICE** × **A_DEFAULT_GHG_RATE**
+ **B_UNSPECIFIED** × $0.001 + **TRANSFERS** × **TRANSMISSION_PRICE**

Constraints

1. All generator dispatch less than or equal to its upper economic limit.

$DISPATCH \leqslant UEL$

2. All transfers between zones less than or equal to the maximum transmission limit.

$TRANSFERS \leqslant TRANSMISSION\_MAX$

3. Unspecified Resources to A and B must be comprised of generation that is not internal to the zone and is not Specified Resource to the zone.

$A\_UNSPECIFIED \leqslant UNSP\_RESOURCE\_MASK \bullet DISPATCH$

$B\_UNSPECIFIED \leqslant UNSP\_RESOURCE\_MASK \bullet DISPATCH$

4. The sum of all transfers from B to C must be designated resources to C

$C\_DES\_RESOURCE\_MASK \bullet DISPATCH \leqslant TRANSFERS(BC)$

5. Specified Resources to A from B must be equal to the transfers from B to A

$(A\_SP\_RESOURCE\_MASK \times B\_GENERATOR\_MASK) \bullet DISPATCH = TRANSFERS(BA)$

6. The sum of Specified and Unspecified Resources from C to B must equal the transfers from C to B

$B\_SP\_RESOURCE\_MASK \bullet DISPATCH + B\_UNSPECIFIED = TRANSFERS(CB)$

7. The sum or Specified and Unspecified Resources from C to A must equal the transfers from C to A

$(A\_SP\_RESOURCE\_MASK \times C\_GENERATOR\_MASK) \bullet DISPATCH + A\_UNSPECIFIED = TRANSFERS(CA)$

8. Emission Constraint on B

$$((B\_GENERATOR\_MASK + B\_SP\_RESOURCE\_MASK) \times EMISSION\_RATE) \bullet DISPATCH +$$
$$B\_DEFAULT\_GHG\_RATE \times B\_UNSPECIFIED -$$
$$(B\_GENERATOR\_MASK \times A\_SP\_RESOURCE\_MASK \times EMISSION\_RATE) \bullet DISPATCH -$$
$$(C\_DES\_RESOURCE\_MASK \times EMISSION\_RATE) \bullet DISPATCH$$
$$\leqslant LOAD(B) \times B\_EMISSION\_RATE\_MAX$$

9. Load sufficiency constraint on A

$(A\_GENERATOR\_MASK + A\_SP\_RESOURCE\_MASK) \bullet DISPATCH + A\_UNSPECIFIED = LOAD(A)$

10. Load sufficiency constraint on B

$((B\_GENERATOR\_MASK \times (I - A\_SP\_RESOURCE\_MASK - C\_DES\_RESOURCE\_MASK)) \bullet DISPATCH + B\_UNSPECIFIED = LOAD(B)$

11. Market Power Balance constraint

Sum[DISPATCH] = Sum[LOAD]

Appendix II. Western States' GHG Reduction Programs

Prepared by the Regulatory Assistance Project

This document briefly summarizes the non-cap-and-trade greenhouse gas reduction policies applicable to the electric sector currently in place in western states. Renewable portfolio standards, which are not explicitly focused on GHG emission reductions, are not covered by this summary. Five western states have GHG reduction requirements applicable to electric utilities. These requirements are sometimes referred to as "non-priced-based" because they do not result in or originate from an explicit price on carbon. All of these standards apply to the load serving entities in the states and the standards are based on the emissions (or emissions rate) attributable to the power used to serve their in-state load. Four of the five have total emissions as the metric for the standard meaning that utilities must reduce total emissions by a certain amount by a certain date. One (NM) has an emissions rate (lbs/ MWh) as the metric for the standard meaning utilities must reduce the carbon intensity of electricity by a certain amount by a certain date.

Colorado
Requires utilities to reduce emissions by 80% by 2030 from 2005 levels and seek to provide 100% clean energy by 2050. Implementation will be through the Air Pollution Control Division (part of the Colorado Department of Public Health and Environment (CDPHE)) and the Public Utilities Commission. There are no alternative compliance options, meaning that utilities must meet the standard through emission reductions only. Clean Energy Plans, which lay out the utilities' plan to comply with these requirements, will be approved by the PUC so long as the plan protects system reliability and results in a reasonable cost to customers.

Oregon
Requires investor-owned utilities to reduce emissions by 80% by 2030, 90% by 2035, and 100% by 2040 from a baseline calculated as the average from the years 2010-2012. Implementation and enforcement will be conducted through the Department of Environmental Quality and Public Utility Commission. There are no alternative compliance options, meaning that utilities must meet the standard through emission reductions only. There are exemptions from the requirements for reliability concerns and for excessive cost to customers, as determined by the PUC. Additionally, investor-owned utilities must eliminate coal from the supply to Oregon customers by 2030.

Washington
Requires electric utilities to eliminate coal from the power supplied to Washington customers by Dec. 31, 2025, provide greenhouse gas neutral power to meet retail electric load by 2030 using non-emitting and renewable generation and up to 20% alternative compliance options, and provide 100% renewable and non-emitting power to meet retail load by 2045 (under the Clean Energy Transformation Act). Electric utilities must demonstrate compliance over four-year periods beginning on Jan. 1, 2030. Alternative compliance options include alternative compliance payments, unbundled RECs, and energy transformation projects as defined by the Department of Ecology. The UTC handles implementation and enforcement for investor-owned utilities and the Department of Commerce for consumer-owned utilities with some role for the

Department of Ecology. There is an alternative compliance method if an electric utility can demonstrate it has met or exceeded an established incremental cost of compliance.

Nevada
Requires utilities to produce at least one IRP scenario that achieves 100% reduction below 2005 levels by 2050 on an ongoing basis and an 80% reduction below 2005 levels by 2030 in their 2024 and/or 2027 IRP filing. The state has a goal of 100% carbon-free electricity serving Nevada customers by 2050. The state also has binding economy-wide GHG reduction targets of 28% below 2005 levels by 2025, 45% by 2030, and zero or net-zero by 2050. The Nevada Department of Environmental Protection is responsible for proposing policies and regulations to achieve GHG reduction goals and reporting on the progress toward achieving the GHG goals. The PUCN is responsible for implementation of the IRP requirements.

New Mexico
Requires utilities that have received approval of a financing order (only PNM) to limit the GHG emissions associated with power purchase agreements of 24 months or longer to no more than 400 pounds of CO2 per MWh by January 1, 2023 and no more than 200 pounds of CO2 per MWh by January 1, 2032. There are no alternative compliance options, and the NM Public Regulation Commission is required to adopt rules to implement these requir