For the published version of this article see:

Gillenwater, M. and C. Breidenich, “Internalizing carbon costs in electricity markets: Using certificates in a load-based emissions trading scheme,” *Energy Policy*, Volume 37, Issue 1, January 2009, Pages 290-299. <http://dx.doi.org/10.1016/j.enpol.2008.08.023>

Internalizing carbon costs in electricity markets

Using certificates in a load-based emissions trading scheme

Discussion Paper
August 2007

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Internalizing carbon costs in electricity markets: Using certificates in a load-based emissions trading scheme

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Abstract

Several western states have stated their intention to develop a regulatory approach to reduce greenhouse gas (GHG) emissions from the electric power industry, referred to as a load-based cap-and-trade scheme. A load-based (LB) approach differs from the traditional source-based (SB) cap-and-trade approach in that the emission reduction obligation is placed upon Load Serving Entities (LSEs), rather than electric generators. The LB approach can potentially reduce the problem of emissions leakage, relative to a source-based system. For any of these proposed LB schemes to be effective, they must be compatible with modern, and increasingly competitive, wholesale electricity markets. LSE's are unlikely to know the emissions associated with their power purchases. Therefore, a key challenge for a LB scheme is how to assign emissions to each LSE. This paper discusses the problems with one model for assigning emissions under a LB scheme and proposes an alternative, using unbundled Generation Emission Attribute Certificates. By providing a mechanism to internalize an emissions price signal at the generator dispatch level, the tradable certificate model addresses both these problems and provides incentives identical to a SB scheme.

1 Introduction

In the United States, a lack of regulatory initiative to address greenhouse gas emissions (GHG) at the federal level has induced state governments to develop their own or regional policies. The electric power industry is the largest contributor to U.S. GHG emissions, accounting for just over 33 percent, and so has been the focus of several state-sponsored initiatives (EPA, 2007).

The policy approach for regulating emissions from the electric power industry adopted in the European Union's Emission Trading Scheme (EU-ETS) and most frequently proposed in the United States is to cap industry-wide emissions at the source and allow emission allowances to be traded between regulated entities. These emission "cap-and-trade" schemes specify that power plants (i.e., electricity generators) that directly emit pollutants, such as carbon dioxide (CO_2), are the regulated entities responsible for compliance.

In general, this type of source-based (SB) cap-and-trade scheme is an efficient means of reducing emissions of the electric power industry. However, if the boundaries of the scheme that specify which entities are capped do not include all or most of the entities operating in the regional electricity market, then emissions reductions from a capped region can be countered by increases in emissions from entities outside the scheme's boundaries. This problem is referred to as emission "leakage."

In attempting to address this problem, several western states have stated their intention to develop an alternative regulatory approach for the electric power industry, referred to as a load-based cap-and-trade scheme. A load-based (LB) approach differs from the traditional SB cap-and-trade approach in that the emission reduction obligation is placed upon Load Serving Entities (LSEs), rather than electric generators.[1] LSEs purchase power wholesale or generate it themselves and then distribute it to retail (i.e., residential, commercial, and industrial) consumers. Allowances, that convey the right to emit one ton of a pollutant, are distributed to LSEs who are then required to surrender allowances to cover aggregate emissions associated with the electricity they sell.

The LB approach to regulating GHG emissions from the electric power industry has been proposed for several states and regions because it can potentially reduce the problem of emissions leakage. States do not have the legal authority to regulate power plants located in other states; however, they do have the authority to regulate LSEs serving retail customers in their state, and thus emissions from all electricity consumed.

To date, Oregon[2] is actively pursuing and California[3] is actively considering an LB approach. Not surprisingly, imports account for a significant fraction of the electrical load served (i.e., retail sales) in each state. In California, net electricity imports account for around 30 percent of total load,[4] but roughly 50 percent of the GHG emissions (CEC, 2007). In contrast, Oregon is a net exporter of electricity in years when snowfall is sufficient for hydroelectric facilities to operate near capacity. However, because of the seasonal nature of hydroelectric power, Oregon's overall consumption of electricity is still heavily dependent on imports from coal-fired power plants in Utah, Wyoming, and Montana (GAGGW, 2004; ODP, 2005).

States in the West and Northeast are also considering an LB approach to a cap-and-trade program. Participants in the Western Regional Climate Initiative, which includes Oregon and California, are considering development of a regional LB scheme. And states that are part of the Regional Greenhouse Gas Initiative (RGGI) are also considering supplementing their SB cap-and-trade scheme with a LB approach that targets only the portion of electricity imported from states not participating in RGGI (e.g., Pennsylvania) (RGGI, 2007).

For any of these proposed LB schemes to be effective, they must be compatible with modern, and increasingly competitive, wholesale electricity markets. These markets are no longer dominated by vertically-integrated utilities. Instead, independent power producers, power marketers and brokers, and spot markets play significant roles.

Because much (if not all) of the load-served by an LSE is purchased from other entities, LSE's are unlikely to know the emissions associated with their power purchases. Therefore, a key challenge for a LB scheme is how to assign emissions to each LSE.

Currently, the most detailed model for assigning emissions to load is that proposed in Oregon. The Oregon model requires that regulators track financial transactions for wholesale power by following the contract-paths between generators and LSEs. This paper discusses the problems with the contract-path model, and proposes an alternative, using unbundled Generation Emission Attribute Certificates (GEACs). This alternative model offers several benefits, most important of which is that it is more compatible with competitive wholesale electricity markets. Although we will briefly contrast the LB approach to an emissions cap-and-trade scheme with a SB approach, this paper does not take a position on whether a SB or LB approach is preferable. Rather, it solely aims to elaborate and justify this alternative model for a LB approach.

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[1] Depending on regulatory definitions, LSEs may be referred to as retail electric providers or retail electric suppliers.
[2] The Oregon Legislative Assembly recently introduced House Bill 3545, which would establish a LB cap-and-trade scheme for LSEs in Oregon. (http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf)
[3]California enacted Assembly Bill 32 in September 2006. The Bill explicitly require that the state account for emissions from both in-state electricity generation and electricity imported from outside the state (http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf). In response, the California Public Utilities Commission has stated its intention to develop a LB emission trading scheme for the electric power sector.
[4] http://www.energy.ca.gov/electricity/gross_system_power.html

2 Load-based cap-and-trade scheme

The LB approach represents an evolution of electricity procurement policies, such as Renewable Portfolio Standards (RPSs) and Emission Performance Standards, both of which mandate the type of electricity procured by an LSE. An LB approach is in many ways analogous to an RPS; however, whereas an RPS requires the tracking of generation from eligible renewable energy technologies that supplies a portion of an LSE's load, a LB approach requires the tracking of all generation, and associated emissions, supplying an LSE's entire load. Regulators and experts in California, in particular, have developed procurement policies to reduce emissions from the electric power industry over the last several years (Potts, 2006).

The tracking and capping of emissions associated with all load served inside a jurisdiction, as opposed to only generation inside a jurisdiction, creates the potential to address emissions from imports and control emissions leakage from a shift to dirtier electricity imports (Burtraw et al., 2006; Cowart, 2006a, b). This shift can take the form of moving facilities, production, or purchases to an unregulated jurisdiction. Because electricity can easily be imported from uncapped sources that do no face emission compliance costs, the potential for leakage is of particular concern for the electric power sector (RGGI, 2007).

2.1 Comparison to a source-based approach

Under a traditional SB cap-and-trade scheme, regulators determine a cap on allowable emissions, and distribute emission allowances (i.e., emission permits) to regulated sources (i.e., electricity generators) equal to the level of the cap. These sources can then trade allowances so that reductions are achieved at the lowest aggregate cost to society.[5] Each source monitors and reports emissions and then surrenders allowances equal to the quantity of its emissions. A SB approach internalizes the cost of pollution at the generator-level, because higher emitting generators face higher compliance costs than low-emission generators. This additional cost reduces the differential between the variable costs of these generators (e.g., coal and gas, respectively), with the result that cleaner generators dispatch more frequently and displace dirtier generation.

A LB approach also regulates emissions through the allocation and surrendering of emission allowances; however, allowances and the obligation to surrender them are instead assigned to LSEs. Under a LB approach, generators face no direct compliance requirement to reduce emissions. However, faced with compliance penalties if they exceed the emissions cap, LSEs will prefer to procure generation from lower emitting sources. Over time, the wholesale electric market should value less-emitting generation.

Advocates of a LB approach over a SB approach commonly cite three advantages. The first is that a LB approach provides regulated entities with a low-cost mitigation option not available to generators under a SB scheme. LSE can invest in improvements in the energy efficiency of their retail customers, thereby lowering their overall load and emissions burden. For the electricity sector, energy efficiency may be the lowest cost mitigation strategy (IPCC, 2007), and many LSEs have extensive experience in managing demand side management programs (Berry, 1993).[6]

A second argument holds that a LB approach provides a better incentive for LSEs to procure electricity from renewable energy generators, because such procurement lowers their emissions, and thus, compliance burden. However, proponents of an SB approach argue that it provides an equivalent incentive for renewable energy investments by raising the relative costs of fossil fuel-fired generation.

Finally, because allowances would be distributed to LSEs, rather than generators, a load-based scheme would eliminate windfall profits accrued by generators under a SB scheme in which allowances

[5] In the case of CO_2 and other GHGs, the ability to trade allowances is especially appropriate, given that the environmental impacts of GHGs are independent of the location of emissions.

[6] The revenue and profits for most LSEs are based on electricity sales. Therefore, unless profits and sales volume have been decoupled, a LSE will only have an incentive to invest in energy efficiency if the emissions compliance cost savings are greater than the lost profits from reduced sales.

are freely allocated (i.e., grandfathered). However, distribution of allowances through auction, on a historical output (i.e. per MWh generated) basis, or to LSEs could also eliminate windfall profits to generators under an SB scheme.

Overall, it is the advent of competitive wholesale electricity markets, where generators and LSEs operate as independent economic actors, that enables the distinction between an LB approach and a SB approach. In some jurisdictions where the electric power industry has not been restructured and electric power utilities continue to operate as vertically integrated monopolies, with generation, transmission, and distribution owned and operated by a single entity, a LB and SB approach are almost equivalent.[7] In these jurisdictions, the advantages of an LB approach over a SB approach will be limited to the issue of controlling emissions leakage.

The key challenge with implementation of a LB approach is assigning emissions to individual LSEs. Because it is physically impossible to track electron flows through a transmission grid, this requires some means of determining which generators are supplying a LSE's power portfolio.

2.2 Contract-path model

The most detailed model to date for a LB approach is that developed by the Oregon Carbon Allocation Taskforce[8] and integrated into Oregon House Bill 3545. This model attempts to determine the mix of generators supplying an individual LSE's load and assigns emissions based on the emission rates of those generators. Where an LSE has a bi-lateral contract with a specific generator or owns a generation asset, the emission rate of that generator is applied to each mega-watt hour (MWh) purchased or produced.

However, much of the power purchased by LSEs is not in the form of unit-specific bilateral contracts. Instead, most LSEs procure a significant fraction of their electricity supply in the form of wholesale contracts that specify the quantity, price and delivery point of power but do not specify a particular generator. Unit-specific emission information is typically unavailable for such power purchases. In some cases, it is possible to track power backwards from a delivery point to a control area[9] using NERC e-tags[10], but not back to a specific generating unit. Similarly, day-ahead and real-time spot markets do not provide information that would allow LSEs to identify individual sellers or generators, as such information could be used for collusion or market manipulation. For the purposes of this paper, power purchased on the spot market or through contracts that are not unit specific is referred to as "unspecified power".

To get around this problem, the Oregon contract-path model assigns a common "residual emission rate" to unspecified power purchases based on an average emission rate of all generation within the Northwest Power Pool not accounted for with unit-specific bilateral contracts or as owned assets. A similar approach is being considered for adoption in California (CEC, 2007).

2.3 Contract-path model flaws

The contract-path model has several serious flaws. The objective of any model for implementing a LB approach should be to preference the dispatch of existing clean generation, and to promote additional investments in new and repowered low-emitting generation capacity.

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[7] Assuming that the same emission sources were covered by both a SB and LB scheme.
[8] http://www.oregon.gov/ENERGY/GBLWRM/CATF.shtml
[9] A control area is a set of interconnected electrical generation sources and sinks overseen by a common 'balancing authority'. The balancing authority is responsible for ensuring that electricity generation, imports to, and exports from a control area balanced with load in that control area.
[10] North American Electric Reliability Corporation (NERC) e-tags are required for power scheduled between control areas. E-tags are not required to schedule power exchanges within a control area.

Despite what one might think, even a LSE's unit-specific bilateral contracts do not necessarily determine which generators are dispatched in competitive wholesale electricity markets.[11] Rather, real-time factors determine dispatch. In U.S. competitive electricity markets, the primary market factors affecting dispatch are the wholesale electricity price in the day-ahead and hour-ahead markets. Generators or marketers bid into these markets based on consideration of the variable cost of operating each generator. The balancing authority or market operator may further adjust this dispatch of individual units based on resource availability, load conditions and transmission constraints. In centrally operated markets, a market operator selects the lowest cost combination of generators to match a given real time load (plus reserves) on behalf of all the LSEs in the control area. A complex financial settlement process then corrects for the differences between contract payments and actual generation though side payments between generators and LSEs (Stoft, 2002).

The implication of contracts not determining generator dispatch is that LSEs can meet their emission obligations through contract shuffling. In contrast to emissions leakage, which involves the actual shifting of generation activities from capped to uncapped sources, contract shuffling refers to a change in the arrangement of power contracts to cleaner generators without a corresponding change in dispatch or emissions. Bushnell et al. (2007) argue that contract shuffling will negate most of the emission reduction benefits from a California LB approach using the contract-path model.[12] Regulators could attempt to eliminate the potential for contract shuffling by requiring unit-specific contracts, but such a requirement will add risk, inefficiency and, hence, costs to electricity markets.

The second flaw in the contract-path model is that it does not distinguish between electricity from low and high emission generators when it is sold as unspecified power. Therefore, the model does not signal the cost of pollution to these generators. Instead, the model provides an incentive for dirty generators to hide behind the default emission rate by selling power through unspecified contracts or the spot market.

Some analysts have suggested the further disaggregation of emission rates for unspecified power by source control area and by base/peak load periods, using marginal dispatch analyses (Alvarado and Griffin, 2007). Such an approach could more accurately estimate the system emission mix at different load periods, but it would not reduce the ability of LSEs to use contract shuffling to reduce their apparent emissions.

Finally, the proposed formulation of the contract-path model provides LSEs no control over their emissions burden from unspecified power purchases. The only option for an LSE to lower the emissions associated with its load is to move from a system power purchase to unit-specific contract. This is problematic, as unspecified power purchases play an important role in ensuring the reliability and efficiency of electricity markets.

3 Tradable certificate model

Instead of relying on the tracking of contracts and a default emission rate for unspecified power, an alternative model would use generation emission attribute certificates (GEACs) to assign emissions to each LSE. A GEAC would be created for each mega-watt-hour (MWh) of net generation and contain data on the direct (i.e., on-site) emission rate (e.g., tons CO_2/MWh) of a specific generator (e.g., renewables would create GEACs with a zero emission rate) (Breidenich and Gillenwater, 2007; Gillenwater, 2007).[13] These certificates would be registered based on metered generator output and verified emissions rates, and tracked within a registry database.

[11] There are exceptions. Generators will occasionally enter into inflexible contracts that require the generator to bid into the market at zero cost to ensure that the generator will be dispatched. These contracts are considered risky for both the generator and LSE and are thus the exception rather than the norm.

[12] Bushnell (2007) also suggest that and a RPS would be better approach to address GHG emissions. However, an RPS does not provide any incentive for generation from natural gas over coal.

[13] Renewable Energy Certificates (RECs) are another type of generation attribute. As RECs are not designed to track emissions associated with generation, the authors consider them distinct from a GEAC.

Each LSE would be required to purchase GEACs equivalent to its load served and its total emissions would be calculated by summing the emission rate of each certificate. The LSE would then be required to surrender emission allowances equal to its final emission burden.

Because GEACs would be traded separately from electricity (i.e., unbundled), unit-specific contracts would not allow an LSE claim a generator's emission rate.[14] Rather, the LSE must acquire and surrender GEACs in order to claim a specific emission rate.

Registries to track the creation, transfer and disposition of generation attribute certificates are already in operation in the Middle-Atlantic states (i.e., the PJM Interconnections Generation Attribute Tracking System[15]), New England (i.e., ISO New England's Generation Information System[16]), and Texas[17]. Similar systems are being developed in New York state, the Midwest (Midwest Renewable Energy Tracking System[18]), and the Western states (Western Renewable Energy Generation Information System[19]) that includes California and Oregon (Holt and Wiser, 2007).

3.1 Model description

Under a simplified version of tradable certificate model, each LSE would be required to purchase and surrender a quantity of GEACs, denoted in MWh, equivalent to its load served. A LSE's attributed emission would be calculated by adding the emission rates of all of its GEACs. Each LSE would then be required to surrender allowances equivalent to its attributed emissions for compliance (Equation 1).

$$A = \sum_{i=1}^{C} \left(CR_i \right), \qquad \text{subject to the constraint that } C = L \qquad \text{[Equation 1]}$$

where,

A = number of allowances required by an LSE for compliance
C = the number of certificates submitted by an LSE
CR = the emission rate of an individual certificate (tonnes/MWh)
L = load delivered to end-use customers by an LSE (rounded up to the nearest MWh).

The simplified model above works if the generation within the capped area is equal to load, and if all generation is certified and sold to LSEs. However, if the generation within the capped area is less than total load (which would be expected in state which is a net importer of electricity), then the quantity of certificates will be insufficient to cover each LSE's load. Further, while a state could require that all in-state generators must certify their output, such a legal requirement would be difficult to apply to out-of-state generators.

To address these limitations, a more practical version of the model employs a default emission rate for the portion of a LSE's load not matched with GEACs. The use of a default emission rate eliminates the constraint in Equation 1 that the supply of certificates must equal the load of all LSEs, since the default emission rate would be applied to any load not covered by certificates. It also eliminates the need to track generation and emissions from all facilities. If the supply of GEACs can be constrained (see section 3.3), generators with emission rates below default rate will receive a positive price for their

[14] Although LSEs could contract to purchase both electricity and certificates from a given generator.
[15] http://www.pjm-eis.com/gats/gats.html/
[16] http://www.nepoolgis.com/
[17] http://www.texasrenewables.com/
[18] http://mrets.net/
[19] http://www.westgov.org/wieb/wregis/

GEACs, and thus will have an incentive to certify their output. Generators with emission rates at or above the default rate will have no need to register GEACs, as these would have little or no market value.

Each LSE's emissions burden is then calculated based on the GEACs it purchases from low or zero emitting generators. The fraction of an LSE's load not matched with certificates is assigned a default emissions rate (Equation 2). To signal the cost of pollution to all generators, the default emission rate should be set at or just below the emission rate of the dirtiest generators serving load.[20] If the default emission rate is set at a lower value, such as the average emission rate of all generators, then all generators with an emission rate higher than the default would be attributed the same emission rate. Thus, the use of a high default emission rate provides an incentive for generators to reduce their emissions and certify their power production in order to gain certificate revenue. It also provides an incentive for LSEs to purchase GEACs to avoid being attributed emissions based on the high default rate.

$$A = \left[(L - C) \times DR\right] + \sum_{i=1}^{C} (CR_i) \qquad \text{[Equation 2]}$$

where,

DR = the default emission rate (tonnes/MWh).

Figure 1 below provides an example of how the purchase of GEACs reduces an LSE's obligation to surrender allowances.

Figure 1. Example calculation for determining LSE compliance using the certificate-based model

Default emission rate: 1 metric ton CO_2/MWh
Total load-served by LSE: 100 MWh
Starting allowance obligation: 100 metric tons CO_2 (100 MWh · 1 metric ton/MWh)

GEACs purchased and surrendered:
50 certificates at 0.5 metric tons/MWh
20 certificates at 0 metric tons/MWh

LSE's allowance obligation: 55 metric tons CO_2
(50 MWh · 0.5 metric tons/MWh) + (20 MWh · 0 metric tons/MWh) + (30 MWh · 1 metric ton/MWh)

3.2 Advantages

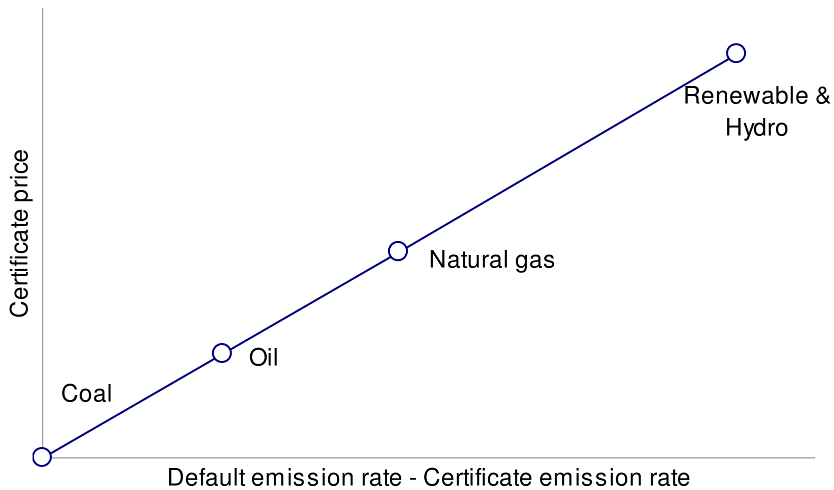
The tradable certificate model has several advantages over the contract-path model. Most importantly, the certificate model internalizes the cost of pollution at the generator-level because it preferentially provides lower emission generators with a new revenue stream. Eligible electricity generators would be able to sell GEACs to LSEs and other market participants, thereby gaining an additional revenue stream. Lower emission rate certificates would trade at a premium price, as they would lower the quantity of allowances that the LSE must surrender for compliance. The GEAC revenue would reduce the variable cost of generation, allowing cleaner generators to bid in at lower electricity prices.

[20] Setting the default rate at a level significantly below the dirtiest generator would effectively exclude that portion of generators with emissions above the default rate from the scheme. Therefore, we do not recommend setting the default rate below that of an inefficient coal-fired unit.

GEACs thus have the effect of subsidizing low and zero-carbon generation, with the subsidy provided by LSEs and other market participants rather than government agencies (Gillenwater, 2007).[21]

The market price of GEACs, on an emission rate weighted basis, will track the price of emission allowances, since purchasing certificates represent an alternative compliance option to submitting allowances; the purchase of GEACs reduces the quantity of allowances the LSE must surrender. Therefore, as shown in Figure 2, the equilibrium price of each GEAC should equal the difference between the certificate's emission rate and the default emission rate, multiplied by the allowance price.

Figure 2: Certificate price as a function of emission rate



Note: Assumes that default emission rate is set at a level equivalent to a typical coal-fired unit.

The additional revenue from certificates is particularly important for natural gas-fired plants that face higher fuel costs than coal-fired plants. The additional revenue from certificate sales will cover a portion of a gas-fired generator's variable costs enabling that generator to submit lower bid prices into the wholesale electricity market. The certificates thus provide a clear financial incentive for more frequent dispatching of higher variable cost generators with lower emission rates. It also provides a direct financial incentive for investments in zero and low-emitting generation capacity.

Because certificate revenue will enable some generators to dispatch at lower electricity prices than possible in the absence of the revenue, GEACs will place downward pressure on wholesale electricity prices. This decrease in wholesale electricity prices should largely offset the additional costs that LSEs would incur for purchase of GEACs.[22]

The GEAC model also avoids the difficulties and complexity with tracking contract-paths. By unbundling certificates from wholesale electricity transactions, GEACs can trade in a separate market from electricity. The only data required for implementing the tradable certificate model is metered output and emission rate data.

[21] The effect of this subsidy on the dispatch of hydroelectric and nuclear units is likely to be negligible. The authors have considered excluding large existing hydroelectric and nuclear generators from the scheme. Alternatively, the government could appropriate the certificates from these facilities and use the revenue from their sale for program administration and public benefit investments. An elaboration of these issues is beyond the scope of this paper.

[22] Modeling of the price dynamics within competitive wholesale electricity markets where electricity, certificates, and allowances are all simultaneously transacted is recommended as an area for future research to better illustrate the impacts on retail electricity prices.

3.3 Certificate supply

If the boundaries of a LB scheme match those of the regional wholesale electricity market, as would be the case if all states within the Western Interconnect adopted a LB scheme, then the output of all generators in the region would equal the region's total load. Assuming that the scheme's emissions cap creates a scarcity in emission allowances, then certificates from low-emitting generators will have a positive price. Under these conditions, GEAC revenue can be expected to alter the dispatch of generators and thus emissions within the capped region.[23]

However, if the boundaries of the scheme are narrower than the wholesale electricity market, then the potential supply of low-emission certificates may greatly exceed the scheme's demand (i.e., regulated load). The result will be that certificate prices will reflect the market's transaction costs only and provide little or no financial incentive for greater dispatch of or investments in cleaner generation capacity. In addition, the supply of low emission certificates would free up allowances that would otherwise be surrendered to cover emissions, thereby resulting in emissions leakage. This problem is analogous to the contract-shuffling problem discussed above, in that under this scenario, the purchase of low-emission certificates will have no effect on generator dispatch and thus will not reduce emissions.

The challenge, then, is constraining the supply of certificates that may be used in the capped region.[24] Any approach to restricting certificate supply should meet several basic criteria:

- First, it should limit the supply of certificates that can be used in capped market to a quantity that is approximately equal to the load-served in the capped area.
- Second, the approach must be consistent with the open exchange of power in competitive electricity markets, and should not provide new incentives or disincentives for unspecified power purchases.
- Third, it should minimize the uncertainty generators face regarding their eligibility to sell certificates into a capped region, so that they can factor any expected certificate revenue into their electricity bids.

For California, which is a net importer of power, the central problem is restricting purchases of out-of-state certificates to the quantity of net imported power, since in-state generators can reasonably be assumed to be serving in-state load. However, while restricting the quantity of imported certificates would not directly restrict power imports, it would potentially be vulnerable to legal challenges that it violates the Interstate Commerce Clause of the U.S. Constitution. The Commerce Clause has been interpreted as imposing two basic limitations on state authority: state regulations may not explicitly discriminate against other states and these regulations must not disproportionately impact other states. The latter requirement, in particular, requires balancing of the regulating state's interest, against the potential harm to neighboring states. Although an analysis of the legal implications of the certificate model is beyond the scope of this paper, the equivalent treatment of in-state and out-of-state power is a fourth criterion that any approach to restricting supply must meet.[25, 26] Any approach that limits the eligibility of certificates to generators within the capped region (or state) is may fail this test.

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[23] The extent to which the GEAC model will affect dispatch will depend on allowance prices, just as would be expected under a SB system. Analysis suggests that allowance prices in the range of $20 to $50/metric ton, depending on gas prices and available generation, would be required to equalize the variable cost of natural gas and coal generation and thus affect dispatch (Niemeyer, 2007).

[24] See Grace and Wiser (2002) for discussion of various methods to address certificate imports and exports.

[25] See Potts (2006) and Engel (1999) for discussions of the potential commerce clause issues, including the Pike balancing test (*Pike v. Bruce Church, Inc*., U.S. Supreme Court, 1970). It should be noted that many state RPS requirements that discriminate between in-state and out-of-state renewable generation appear to be vulnerable to commerce clause challenges, yet have not been challenged (Rabe, 2006). However, this may be due to the fact that affected generators have more to gain from RPS legislation than from challenging any individual state requirement.

[26] The first seller approach recommended to the state of California by its Market Advisory Committee, may suffer from similar legal and federal regulatory challenges (e.g., under the Federal Energy Regulatory Commission) due to the requirements it places on out of state entities to purchase allowances.
<http://www.climatechange.ca.gov/policies/market_advisory.htm>l

For states or regions that are net exporters of power, the tradable certificate model can also lead to an oversupply of certificates. This problem is easier to address because regulators would not face legal impediments to placing reporting or other requirements on generators within their jurisdiction. Net exporting states could exclude the electricity exported from their LB scheme, thereby maintaining a balance between certificate supply and demand. Alternatively, if exports are small relative to electricity consumed within the capped region, exports could be disregarded. Any oversupply of certificates would then be compensated through setting a tighter cap on emissions. In effect, certificate purchases by in-state LSEs would then result in emission reductions for all electricity generated in the state, whether or not it was consumed in the state.[27]

3.3.1 Scheduled delivery restriction

The ideal approach to limiting the certificate supply would be to restrict certificate eligibility to power delivered into the capped area. This approach has conceptual appeal in that certificate revenue would accrue to generators actually supplying load. Because of the impossibility of tracking electricity from source to sink, this restriction is not feasible. However, a reasonable proxy can be achieved by restricting valid certificates to generation *scheduled for delivery* into the capped area. For an area that is a net importer of electricity, in-state generators would be assumed to be supplying native load. Thus, all GEACs generated would be valid for use within the capped area. For out-of-region generators, only certificates associated with power scheduled for delivery into the capped region would be eligible for use within the capped region. This restriction would be implemented using NERC e-tags. Regulators would need to establish a rule that out-of-state generators must produce a valid NERC e-tag for scheduled delivery into the region in order for the associated certificate to be used within the region. Although generator-specific information, is not typically provided on most NERC e-tags (Rush and Hoffman, 2007) the potential certificate revenue would provide the incentive for generators to provide that information. If necessary, the e-tags could be verified against the records of the appropriate control area.

If electricity exports from the area are substantial, a scheduled delivery restriction can also be used to prevent use of GEACs associated with electricity exports. Regulators could require that all in-region generators certify all dispatch, and provide all export schedules (i.e., NERC e-tags) to the tracking registry. Any electricity scheduled for export by a generator would be subtracted from total generation, so that GEACs are issued only for power delivered in-region.

A scheduled delivery restriction would ensure that the supply of eligible GEACs is approximately equal to load within the capped region. There may be some discrepancies due to real-time balancing (with no associated e-tags), but these are likely to be minor. A scheduled delivery restriction would allow generators to factor expected certificate revenue into their bid schedules within the wholesale electricity market in the capped region. Finally, because it makes no distinction between in-state and out-of-state generators, this model should not be vulnerable to Commerce Clause challenges.

3.4 Design issues and implementation

A number of other issues must be considered in the design and implementation of a LB cap-and-trade scheme based on the tradable certificate model. First, the appropriate level of the cap must be determined. Second, a formula for allocating or auctioning emission allowances to LSEs must be established. Third, pre-existing contractual, financial, and regulatory arrangements with electricity generators would need to be assessed to establish rules regarding the ownership of certificates. Fourth, reliable emissions and generation monitoring procedures must be defined. Lastly, rules and systems to ensure efficient and liquid markets for allowances and GEACs must be created.

[27] Although not a feasible scenario at this time, the limit to this alternative is where the supply of zero emission certificates from in-state generators exceeds the total demand for certificates in the capped region.

3.4.1 Baselines and allowance allocation

Under a SB scheme, allowances are either given away to generators or auctioned. The revenue from auctions is typically then used for some public benefit purpose. For a LB scheme, similar decisions are required for the allowances allocated to LSEs.

Regardless of whether generators pay for allowances (i.e., under an auction) or receive them free (i.e., grandfathered), under an SB approach the opportunity cost of the allowance is passed on to consumers in higher wholesale electricity prices. Therefore, the auctioning of some fraction of allowances under a SB scheme is likely to be necessary to avoid windfall profits being captured by generators (Palmer et al., 2006; Sijm et al., 2006).

Under a LB scheme, however, free allocation of allowances to LSEs is likely to be preferable. Whether allowances are freely allocated or auctioned to LSEs, it will not affect the dispatch or investment patterns of generators (Burtraw et al., 2006). Further, retail electricity rates are not based on a marginal market clearing price of electricity, but are instead regulated by public utility commissions. Therefore, the ability of LSEs to raise prices and gain windfall profits is limited. Under the GEAC model, while LSEs must pay for GEACs, these payments will partly be returned to the LSE through lower wholesale power prices. Regulators may still wish to auction a fraction of allowances to raise revenue for some public benefit programs, but LSEs would then have a valid rationale for raising retail electricity rates to recover the costs of purchasing allowances. Although the LB approach avoids the necessity of deciding whether and how much to auction, it is still necessary to decide on the method for distributing allowances to individual LSEs.

The contract-path model typically calls for setting an emissions baseline for each LSE. For example, under the Oregon proposal each LSE's baseline is based on the emissions rate of its historical electricity purchases, accounting for unit-specific bilateral contracts, system power, and imports. This is necessary to create a baseline that is consistent with how emissions are calculated and assigned during the compliance period. Collecting and verifying this data is a significant administrative burden for both LSEs and regulators.

Under the tradable-certificate model, however, the allocation process can be significantly simplified. Because each LSE's emissions are calculated independently of its power purchases or power assets and all LSEs have access to GEACs, it is not necessary to factor historic emission into the calculation of a LSE's baseline. Rather, all LSEs should receive an equal allocation of allowances on a load-weighted basis. Only data on each LSE's forecasted load in MWh are necessary. Of course, regulators will need to consider and plan for significant changes in an LSE's load, including possible load increases due to policies to reduce emissions (e.g. port electrification, or promotion of plug-in electric hybrid vehicles).

3.4.2 Certificate ownership issues

GEACs will have a market value related to their assigned emission rate because generators and other wholesale electricity market participants will have a strong interest in claiming ownership of certificates. For example, a wholesale electricity broker with an existing contract with a wind power generator may claim that his contract implicitly transfers ownership of GEACs. These types of certificate ownership issues could be especially problematic during the start of a scheme until language filters into all wholesale market contracts explicitly identifying ownership of certificates. Uncertainties regarding the ownership of GEACs would significantly weaken the incentives for certification of power and for new low-emitting generation investments.

For this reason, policy decisions prior to the launch of a LB scheme will be needed address certificate ownership issues under all possible scenarios to avoid unnecessary litigation and uncertainty. Renewable Energy Certificate (REC) markets have started to address similar certificate ownership issues, in particular with qualifying facilities (QFs) under Public Utility Regulatory Policies Act of 1978 (PURPA), net metered generation, and other generators receiving some type of financial assistance (Holt et al., 2006). Experiences in the REC markets can provide lessons for addressing ownership issues under the GEAC model.

3.4.3 Compliance monitoring

Identical to a SB scheme, a LB scheme requires reliable emissions data to be collected from generators. The lessons regarding emissions monitoring from existing cap-and-trade schemes such as the U.S. Acid Rain Program and the EU-ETS can be applied here (Kruger and Pizer, 2004; Stavins, 1998). In addition to emissions data, net generation data (MWh) must also be collected in parallel to calculate a generator-specific emission rate. This rate should be updated at a regular frequency.

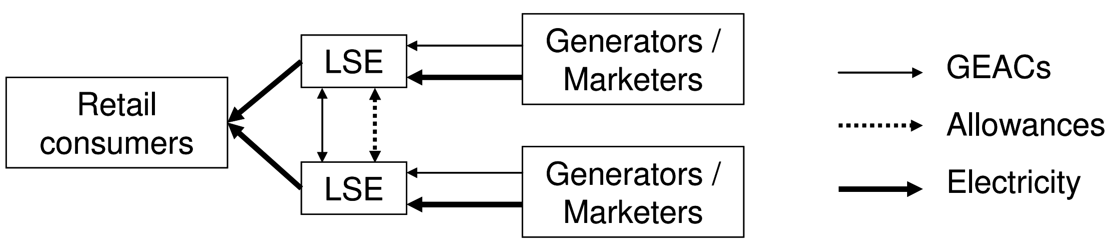
Once data is collected and verified, GEAC for each MWh generated can then be created in a registry database and recorded with a specific emission rate. Certificates in the registry can then be transferred, submitted for compliance, or voluntarily retired.

A unique issue with a LB approach is that it must account for electrical losses due to transmission and distribution. The national average for these losses is about 7 percent (CCTP, 2005), although loss values can vary significantly by region, with rural areas having higher loss percentages. Failing to account for these losses could lead to an excess supply of GEACs on the market. The simplest approach to address this problem would be to upwardly adjust each LSEs load served value (i.e., L in Equation 2) by a percentage that accounts for the region's average transmission and distribution losses. If the difference in line losses varies significantly between LSEs, individual adjustments in L and the number of allowances allocated may be appropriate.

3.4.4 Market efficiency and liquidity

Both the SB and LB schemes create a new allowance market in parallel to the existing wholesale electricity market. Under the tradable certificate model, a third market in GEACs is also created (Figure 3).

Figure 3: Three commodities under the tradable certificate model for a load-based cap-and trade scheme



Under a LB scheme, the number of participants in the allowance market is likely to be less than in a SB scheme (i.e., fewer LSEs in a jurisdiction than generators). Therefore, liquidity and market manipulation risks are likely greater with a LB scheme. The addition of generators as participants through the GEAC market will likely add some complexity to the marketplace, but may improve market liquidity, because it adds generators as market participants, and GEACs as allowance substitutes.[28] Allowing banking of allowances across compliance periods should further improve both market efficiency and liquidity.

To achieve these improvements, especially given the added complexity of having three commodity markets, it is important that systems be put in place to ensure a transparent market. Such systems include transparent certificate and allowance registries, open commodity exchanges, and frequent

[28] Modeling of the electric power industry with the addition of both allowance and certificate markets may help clarify the likely market dynamics.

reporting of generation and emissions rate data. The addition of a market for certificates also has the potential serve as a price discovery mechanism for allowances because certificate prices will have a predictable relationship with allowance prices.

4 Linkages with other trading schemes and policies

A LB cap-and-trade scheme using the tradable certificate model can be linked with SB trading schemes and used to support a variety of other energy and environmental policies.

Because an allowance represents a legal permit to emit a ton of pollutant under both a SB or LB scheme, there should be no barriers to linking a LB scheme with a SB scheme addressing the electric power industry, such as the EU-ETS or RGGI, or a broader economy-wide SB scheme, provided that the boundaries of the two schemes do not overlap.[29] However, while allowances would trade freely across the SB and LB system and across sectors, GEACs would only be traded within the electricity sector of certificate-based LB systems. Similarly, emission offset crediting provisions could be integrated with a LB scheme using either model with no extra difficulty compared with a SB schemes.

It would also be technically feasible to establish a national or multinational certificate based LB cap-and-trade scheme for the electric power industry. The benefits of such an approach would be similar on a national and multinational level as they are on regional level (e.g., addressing emissions leakage, facilitating energy efficiency, integration with RPS mandates). However, a national or multinational scheme would need to satisfy international trade rules with respect to the treatment of imported power (Horlick et al., 2002). In addition, the current design of emissions accounting under the United Nations Framework Convention on Climate Change and the Kyoto Protocol is based on the geographic location of sources. Therefore, a unilateral LB approach that accounted for emissions from international electricity imports would be inconsistent with the reporting framework for these treaties. However, Article 4 of the Kyoto Protocol allows two or more countries to cooperatively account for emissions, and would thus provide an opportunity for these countries to implement a LB system within the framework of the treaty.

GEACs can be used to support utility public disclosure policies, and voluntary green power markets. Voluntary green power and emission market participants can be allowed to purchase and retire both GEACs and emission allowances. If consumer wishes to claim emission reductions, then emission allowances, not GEACs, are the appropriate commodity to retire because the exact amount of emissions reduced will be unambiguous (i.e., one ton).

GEACS are also compatible with existing RPS mandates. If regulators determine that a REC also conveys the emission attribute of the power (i.e. the GEAC), then RECs used for compliance with an RPS should also be counted towards an LSE’s emissions burden. An RPS then becomes a policy that requires a certain percentage of LSE compliance with the LB cap to be met with renewables.

5 Conclusion

Regardless of whether a LB approach is preferable to a source-based approach, the contract-path model for a LB emissions trading scheme has several flaws that undermine its effectiveness at reducing emissions and its compatibility with the evolution of competitive wholesale electricity markets. By providing a mechanism to internalize an emissions price signal at the generator dispatch level, the alternative tradable certificate model described here addresses both these problems and provides incentives identical to a SB system. Whether the alleged advantages of a LB system in encouraging renewable energy and energy efficiency justify the added complexity of a third commodity market for GEACs is beyond the scope of this paper.

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[29] If the boundaries of a LB system and a SB system overlap, as would be the case if California adopted a LB system and the Federal government adopted a SB system, then emissions could be regulated and priced twice – once at the generator level and again at the LSE level. This problem could be addressed by treating all generators subject to a SB scheme as zero-emissions under a LB scheme.

Acknowledgements

We would like to acknowledge Gary Ackerman, Steve Huhman, Rich Cowart, John Woodley, Michael Oppenheimer, Philip Carver, and Ben Hobbs for their useful comments on the ideas reflected in this paper. The authors are solely responsible for the views expressed and for any errors.

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