California Greenhouse Gas Cap and Generation Variable Costs

White Paper

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Introduction

California will implement a greenhouse gas cap and trade program beginning in 2013 that will apply to electrical power generation, among various other sources of greenhouse gasses. The California ISO Department of Market Monitoring (DMM) has prepared this paper to summarize California's upcoming greenhouse gas cap regulations and outline an approach for incorporating the costs of greenhouse gas allowance costs into the ISO's calculation of generating units' variable costs.

The ISO currently calculates generating units' variable energy costs for energy, start-up, minimum load, and transitions between multi-stage generator configurations. The ISO uses these costs to:

- Create default energy bids used for market power mitigation.[1]
- Calculate bid caps for minimum load and start-up costs.
- Create energy, minimum load and start-up bids in the event a market participant does not submit a required bid.

Market participants will incur costs under the greenhouse gas cap regulations to cover the greenhouse gas emissions of the generation under their control. As these emissions are proportional to a generating unit's energy output, it seems appropriate to include the cost of greenhouse gas allowances in the ISO's calculation of generating units' variable costs.

This paper:

- Provides a brief overview of how California will implement its greenhouse gas cap regulations, as they relate to electrical power generation.
- Summarizes the ISO's calculations of generating units' variable costs for energy, start-up, minimum load, and transitions between multi-stage generator configurations.
- Describes the methods used by other ISOs to account for greenhouse gas emission costs under the Regional Greenhouse Gas Initiative (RGGI) in effect in the eastern United States.
- Outlines a method for the ISO to account for greenhouse gas emission in its calculation of generating unit variable costs. This method calculates CO_2 emissions for each natural gas-fired units based on a standard emission rate and each unit's heat rate and start-up fuel characteristics. It determines the CO_2 compliance instrument price based on a daily published index. Market participants would provide emission rates for other types of resources to the ISO.

California's greenhouse gas cap

California is scheduled to begin to enforce its greenhouse gas cap in 2013 under regulations administered by the California Air Resources Board (CARB). These regulations will apply to various

[1] Default energy bids are calculated for the ISO by Potomac Economics, an independent entity under contract to the ISO.

sources of greenhouse gasses, including electrical power generation. California's greenhouse gas cap is referred to as a "cap and trade program" because it establishes a statewide aggregate cap on greenhouse gas emissions, but not specific limits for individual greenhouse gas sources.

The cap will establish a limited quantity of compliance instruments that entities operating sources of greenhouse gasses, such as electric generators, will have to acquire to cover their greenhouse gas emissions. Because the compliance instruments will be able to be bought and sold, entities will make economic decisions whether to use them to emit greenhouse gasses, or to reduce their emissions and sell the compliance instruments they control to others that cannot reduce emissions as economically.

In the electrical power generation industry, the cap will apply to the emissions of in-state generators and to the emissions of the generation behind energy imported from out of the state. The overall greenhouse gas cap for 2013 will be set at 2 percent below 2012's forecast emissions. The cap will decline 2-3 percent every year until 2020, when it will be about 15 percent below 2012 levels.[2]

A similar cap and trade program, the Regional Greenhouse Gas Initiative (RGGI), has been in effect in the eastern United States since 2009. It covers ten states in the northeast and mid-Atlantic region and is a mandatory CO_2 cap that applies only to the electrical power sector. A number of the states within RGGI are within the eastern ISOs, (i.e. PJM, New York ISO, and ISO New England).

Greenhouse gas compliance instruments

The primary compliance instrument for the California cap will be "allowances" issued by the Air Resources Board. Entities controlling greenhouse gas sources will also be able to meet up to 8 percent of their obligation with "offsets." These offsets will be issued for things such as reforestation projects that reduce greenhouse gasses, and for qualified greenhouse gas reduction actions entities undertook prior to the initial compliance period. Entities will demonstrate compliance by periodically surrendering compliance instruments to the Air Resources Board.

Allowance distribution

The Air Resources Board will distribute allowances by allocating them at no cost to various entities and selling them at periodic auctions. An allowance will convey the right to emit a metric ton of CO_2 ($mtCO_2$).[3]

The Air Resources Board will allocate most of the allowances that will be needed for the electrical power generation sector at no cost to the various utilities that directly serve load. These load-serving utilities will be required to place a portion of their allocated allowances into a consignment account. The Air Resources Board will auction off allowances from this account along with the allowances that have not been allocated to other entities covered by the regulations including generation owners and power importers. The load-serving utilities will be required to use the auction proceeds to offset increased costs due to the greenhouse gas cap or for energy efficiency programs.

[2] http://globalclimate.epri.com/doc/EPRI_Offsets_W10_Background%20Paper_CA%20Offsets_040711_Final2.pdf

[3] In reality, because the greenhouse gas regulations cover other gasses besides CO_2, an allowance conveys a right to emit a metric ton of CO_2 equivalent. However, the vast majority of the ISO generation fleet emits negligible amounts of these other gasses.

The auctions will start in August 2012 and continue quarterly after that. Each auction will include allowances for the current year and a portion of allowances for three years in the future. Each year's allowances will be auctioned through sealed bids. A single allowance price applicable will be set based on the highest priced bid accepted. The auction settlement prices and the names of the bidders will be public information, but the allowance quantities purchased at each auction will only be released as aggregated information.

The auctions will have a reserve, or floor, price that will initially be $10 per allowance. To limit the price of allowances, 4 percent of allowances will be set aside to be sold at set prices that will initially range from $40-$50 per allowance. Both the reserve price and the price of allowances set aside to be sold at fixed prices will increase annually after 2013 by 5 percent plus the rate of inflation.

Bilateral trading of allowances will be allowed. Entities will be required to report these trades and the transaction price to the Air Resources Board through its "Market Tracking System "once the exchange takes place. The Air Resources Board will publically release the prices of completed transfers.

Forward contracts for California carbon allowance are currently trading on the InterContinental Exchange (ICE). The price published on December 9, 2011 for forward contracts for 2013 vintage California allowances for delivery in December 2013 is $15.70 per allowance.4 This equates to a cost of $8.35/MWh for a natural gas fired unit with a 10 MMBtu/MWh heat rate. 5

The cost of carbon allowances to electricity generation facilities varies with the output of the facility, and as such is expected to be included in the variable cost and energy bids from affected units. This will have an impact on the wholesale price for electricity in California and potentially other states in the western region. Because of this linkage, it is important that the market for carbon allowance is both efficient and free of market manipulation. To this end, the Air Resources Board has required that there exist an independent market monitor for the carbon allowance market.

Compliance

Entities that control greenhouse gas sources will demonstrate compliance by periodically surrendering compliance instruments to the Air Resources Board as follows:

- Every year they will have to surrender compliance instruments for at least 30 percent of their emissions in that year.
- Every 3 years they will have to submit compliance instruments for the remainder of their emissions during the 3-year period.

Each allowance will have a *vintage,* or the year for which it is issued by the Air Resources Board. Allowances that have a vintage for the year in which they are being submitted or an earlier year can be used for compliance. Allowances with vintages in future years cannot be used for compliance.

[4] https://www.theice.com/marketdata/reports/ReportCenter.shtml?reportId=10

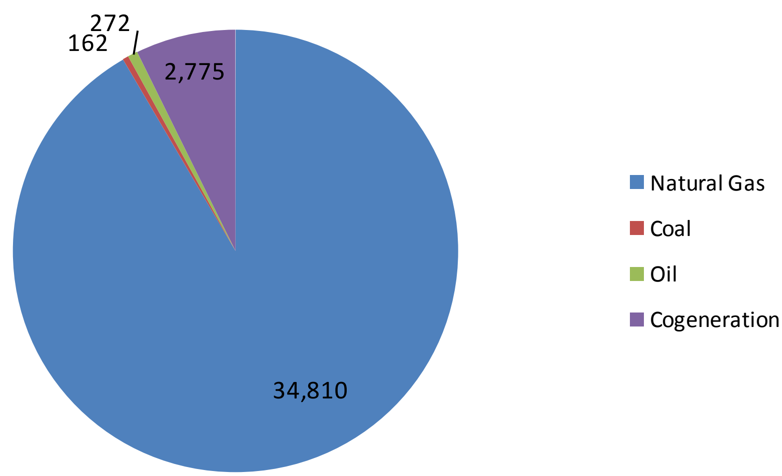
[5] $8.35/MWh = (10 MMBtu/MWh) (0.053165 mtCO_2/MMBtu) ($15.70/allowance) (1 allowance/ mtCO_2), this calculation is explained further down in this paper.

Applicability

The California greenhouse gas cap regulations will apply to in-state generators that emit at least 25,000 mtCO2 equivalents annually. These are generators that use combustible fuels, including natural gas, coal, and oil. Geothermal generators and most biomass/biogas generators are subject to the reporting requirements but are exempt from the requirement to surrender compliance instruments for their emissions. [6]

There are about 38,000 MW of generation in the ISO that use combustible fuels and for which the ISO calculates variable costs for energy, start-up, minimum load, or transitions between multi-stage generator configurations. Of this amount, the actual amount subject to the greenhouse gas cap regulations is probably somewhat less because some units are likely either too small or do not operate frequently enough to emit enough annual CO2 to have to comply with the regulations. The figure below breaks out this generation by fuel-type, showing the vast majority is natural gas-fired.

Generation Subject to Greenhouse Gas Regulations for which ISO Calculates Variable Costs



The greenhouse gasses related to electrical power generation include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_20), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6). The regulations provide global warming potential adjustment factors to adjust these gasses to CO_2 equivalents. CO_2, CH_4, and N_20 are all produced by natural gas combustion, the fuel used by the vast majority of the ISO generation fleet that uses combustible fuels, but only CO_2 is produced in significant amounts. Generators may also emit CO_2 from acid gas scrubbers, SF_6 from circuit breakers and other equipment, HFC from cooling units, and CH_4 from coal storage. [7]

The greenhouse cap regulations will classify imports as coming from specified or unspecified sources. Imports will be subject to the regulations to the extent they come from a specified source that emits at least 25,000 mtCO_2 annually. Emissions from specified sources will be calculated at the emission rate of

[6] http://www.arb.ca.gov/regact/2010/capandtrade10/finalfro.pdf § 95812. (c)(1) page 46, § 95852.2. (b)(1) pages 84-86

[7] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/08_ElectricitySec.pdf

the specific source. All imports from unspecified sources are subject to the regulations and their associated emissions are calculated at a default rate. The entity that is listed as the purchasing-selling entity on the e-tag at the point the energy enters California will have the compliance obligation under the greenhouse gas cap regulations.

ISO's generator variable costs calculations

The ISO calculates various components of generation variable costs. This section provides an overview of these various components of variable costs and the various ways that the ISO markets use these costs. This provides a frame of reference for considering how to incorporate the cost of greenhouse gas compliance instruments into the ISO's calculations.

Energy bids for generators in the ISO market consist of three-parts: energy, start-up, and minimum load. Additionally, multi-stage generators have transition costs to move from one configuration to another. Although market participants submit these energy bid components, the ISO calculates each generating unit's actual variable costs for these components using set formulas. The ISO uses its calculation of these costs to:

- Create default energy bids used for local market power mitigation.
- Calculate bid caps for minimum load and start-up costs.
- Create energy, start-up, and minimum load bids in the event a market participant does not submit a required bid.
- Calculate daily transition costs based on current gas prices to dispatch multi-stage generators.

Bids for imported energy include only an energy bid component and do not include start-up, minimum load or transition cost components. The ISO does not calculate default energy bids for imported energy because import bids are not subject to local market power mitigation. Although the ISO creates bids for imported energy if a required bid is not submitted by a market participant, these bids are not based on actual costs unless actual costs are negotiated on a case-by-case basis with Potomac Economics, the independent entity contracted by the ISO to calculate default energy bids and negotiate variable costs of generation if they differ from the standard values used by the ISO. Since the ISO does not calculate costs for imported energy, the following sections do not discuss these costs further.

Energy costs

The ISO calculates generating units' variable costs to provide incremental energy above minimum load for two purposes:

- Calculating *default energy bids* that are used in the local market power mitigation process if the generation owner has elected the cost-based option for default energy bids.[8]
- Creating energy bids if a required bid is not submitted for a unit.

[8] See footnote 1.

The ISO's local market power mitigation process reduces energy bids to the default energy bid for a unit in the event a unit is flagged as having market power. Market participants can elect to have the ISO calculate a unit's default energy bid calculated using one of three options:

- Variable Cost Option: The ISO calculates default energy bids for each unit for several output levels submitted by the market participant. For each of these output levels, the ISO determines the unit's incremental fuel costs and adds a standard variable operations and maintenance cost. It then adds 10 percent to this amount.[9] For natural gas-fired units, the ISO bases fuel costs on the unit's incremental heat rate multiplied by a standard current daily natural gas cost. For non-gas-fired units, the ISO uses fuel cost based on per MWh fuel costs submitted by the unit's owner and verified by the ISO.

- LMP Option: The ISO calculates default energy bids based on the past locational marginal prices at a unit's location.

- Negotiated Option: The market participant negotiates a unit's actual costs that the ISO will use for the unit's default energy bids with Potomac Economics. These costs typically involve components that are not considered in the standard formula and inputs (e.g. variable operations and maintenance costs) used under the variable cost default energy bid option.

The ISO creates bids if a required bid is not submitted for a unit using the same methodology as the cost-based default energy bid option but without the 10 percent adder.

Start-up and minimum load costs

The ISO calculates units' start-up costs based on a unit's start-up fuel and natural gas prices. Minimum load costs are calculated based on a unit's heat rate characteristics and natural gas prices.[10] The ISO also includes standard per MWh operations and maintenance cost in its calculation of minimum load costs.[11] The ISO adds 10 percent to its calculation of minimum load costs to arrive at the minimum load costs used by the ISO market. If a unit is not natural-gas fired, then the market participant submits the unit's actual start-up and minimum load costs, which are subject to review by the ISO.

The ISO uses these costs differently depending on whether a market participant has elected the proxy cost or the registered cost option for the start-up or minimum load costs of a unit. Market participants can elect either of these two options for both a unit's start-up and minimum load costs or just the start-up or the minimum load costs. The ISO implements these options as follows:

- Proxy Cost Option: Market participants can submit daily start-up and/or minimum load bids that can be no more than the unit's actual costs. The ISO uses the unit's actual start-up and/or minimum load costs to create a bid if a market participant does not submit a required bid.

[9] The ISO adds an additional amount to default energy bids under the cost-based default energy bid option if a unit's bids are frequently mitigated under the ISO's market power mitigation procedures. The standard operations and maintenance costs depends on the generation technology.

[10] Each natural gas fired unit's start-up fuel requirement is based on the actual heat input required plus the auxiliary electrical power required converted into heat input.

[11] Market participants can negotiate non-standard operations and maintenance costs with Potomac Economics.

- Registered Cost Option: Market participants can submit a start-up and/or minimum load bid that stands for 30 days. This bid can be up to twice the unit's actual costs as calculated by the ISO.

Multi-stage generator transition costs

In addition to start-up and minimum load costs, the ISO accounts for transition costs for multi-stage generators. Currently, the ISO provides a mechanism for market participants to specify their transition costs, subject to rules governing the shape and magnitude of the bids. This is not a cost-based approach and, as such, would not need to be altered to accommodate accounting for emission costs. The current approach, however, does not lend easily to verification and may potentially be leveraged for strategic purposes that are not consistent with competitive behavior. The Department of Market Monitoring has recommended that a cost-based approach be applied to specifying transition costs to avoid these potential issues. A cost-based approach could be applied with separate verifiable fuel and non-fuel components provided for each configuration transition. This approach would also lend to a more explicit inclusion of applicable emissions cost.

Natural gas costs

The ISO uses daily natural gas price indices published by commercial suppliers for the generator costs that it calculates daily.[12] The ISO uses the appropriate price indices for each of the three major load-serving utility regions within the ISO to calculate each generator's natural gas price. The ISO adds a natural gas transportation cost based on the published rates for each of these regions. The ISO uses the average of at least two different natural gas prices from different commercial suppliers to calculate natural gas prices.

The ISO uses published natural gas price futures price information for the generator start-up and minimum load costs that it calculates monthly under the registered cost option. The Henry Hub natural gas futures price for the price of are used because, although it is far from California, it is a widely traded location for futures so it would tend to be a relatively more reliable indication of future prices. The ISO adjusts the Henry Hub futures price to California prices by using the futures prices for basis swaps between Henry Hub and southern and northern California gas prices, respectively. Finally, the ISO adds the appropriate gas transportation rate for within each of the major gas transportation utility regions.

The ISO calculates the Henry Hub price it will use for the following month after the twenty-first day of each month. It uses the average of the futures prices over the first twenty days of the month for physical delivery in the following month. The ISO averages the prices over twenty days to reduce the effect of any temporary price increases or decreases that may be occurring in futures prices on the day the ISO calculates the gas price from the futures price. Similar to the Henry Hub futures price, ISO also averages the basis swaps between Henry Hub and southern and northern California gas prices over the first twenty-one days of each month.

[12] Gas prices used to calculate default energy bids are actually determined by Potomac Economics.

Operations and maintenance costs

The ISO uses two standard variable O&M rates with combustion turbine and reciprocating engine units having the higher rate. The ISO is proposing to expand this to ten different rates that vary by fuel source and technology.

Methods used by other ISOs to account for carbon emissions costs

As previously described, the California greenhouse gas cap and trade program is somewhat similar to the Regional Greenhouse Gas Initiative (RGGI) that applies to a number of these states are belong to the various eastern ISOs (i.e. PJM, New York ISO, ISO New England). Similar to California's program, RGGI consists of an overall cap and allowances that are sold at auction and traded bilaterally.

RGGI's implementation in these ISOs provides a useful benchmark for determining appropriate measures the CAISO should take to accommodate the implementation of California's program. The following table summarizes the methods the eastern ISOs use to account for CO_2 allowance costs under RGGI.

Methods Used by Other ISOs to Account for Greenhouse Gas Costs

ISO	Method
PJM	The cost of RGGI CO_2 allowances are included in the fuel costs submitted by the market participant. Market participants determine their fuel costs according to a standard methodology developed by PJM.[13] This standard methodology allows market participant's flexibility in determining fuel costs. For example, they can use the procurement cost or the daily spot market price, but they have to stick to the same methodology for 30 days. Market participants submit their actual costs for other generating unit variable costs, such as operations and maintenance costs. Market participants can either use procurement cost or the spot market price, for determining a CO_2 allowance price, but generally use daily spot market prices. Market participants submit their own calculation of CO_2 emission rates for each unit.
ISO - NE	ISO-NE calculates CO_2 allowance costs for each generator using standard CO_2 emissions rates based on the type of fuel used by each generator. It multiples these CO_2 emission amounts by each unit's heat rate and the CO_2 allowance price. It bases the CO_2 allowance price on a daily index of the spot market price for RGGI CO_2 allowances provided by a commercial service.[14] Market participants submit their actual costs for other generating unit variable costs, such as operations and maintenance costs.

[13] http://pjm.com/~/media/documents/manuals/m15.ashx.

[14] http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-a.pdf, p.25.

ISO	Method
NYISO	The NYISO calculates CO_2 allowance costs for each generator based on emissions rates for each generator submitted by market participants. The NYISO calculates each generator's CO_2 allowance cost by multiplying its emission rate by its heat rate and the CO_2 allowance price. It bases the CO_2 allowance price on a daily index of the spot market price for RGGI CO_2 allowances provided by a commercial service.[15] Market participants submit their actual costs for other generating unit variable costs, such as operations and maintenance costs.

Greenhouse gas allowance costs

Similar to the eastern ISOs currently covered by RGGI, it is appropriate that the ISO include the costs of greenhouse gas allowances as a variable cost of generation. This section outlines an approach for the ISO to include these costs in its calculation of generating units' variable costs for incremental energy, minimum load energy, start-ups, and multi-stage generator transitions.

DMM recommends the ISO calculate the cost of greenhouse gas allowances for natural gas-fired generation based on its calculation of each unit's CO_2 emissions and the price of allowances. Because each generator's CO_2 emissions are proportional to the amount of fuel that it burns, the ISO would calculate each unit's greenhouse gas emissions based on the unit's heat rate characteristics and a standard emission rate. For generating units that use other types of fuels, market participants could provide the ISO with the unit's greenhouse gas emission rate (rate per MMBtu). This emission rate would be subject to verification by the ISO. This approach would be consistent with the ISO's current approach of only calculating fuel costs for gas-fired generators. Fuel costs for other types of units are submitted by market participants and verified by the ISO.

Under the California greenhouse gas cap regulations, market participants will determine the emissions of the generation under their control using methods specified in Air Resources Board regulations.[16] These methods range from taking continuous direct physical measurements of greenhouse gas emissions to calculating the emissions based on standard emission rates determined by the fuel type and the amount of fuel burned. As described above, DMM proposes that the ISO use the later method to calculate the variable costs of natural gas fired generation. In the event this method resulted in emissions rates that were significantly different than a generator's actual emissions, a potential accommodation might be to allow market participant to have the option to submit the actual emission rate of a natural gas unit if they could document the actual emission rate was greater than the standard rate used by the ISO.

The only greenhouse gas emissions that should be included in the ISO's calculation of generating unit variable costs are those that vary with output. Consequently, emissions such as fugitive SF_6 from circuit breakers and other equipment should not be included.

[15] http://www.nyiso.com/public/webdocs/documents/tariffs/market_services/att_h.pdf, First Revised Sheet No. 470C.

[16] Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations), http://www.arb.ca.gov/regact/2010/ghg2010/mrrfro.pdf.

Of the eastern ISO's that currently account for greenhouse gas allowance costs, the approach DMM outlines in this section is most similar to the ISO New England approach (i.e. use both standard emission rates and daily spot market allowance prices based on a published index). This approach seems most consistent with the ISO's general methodology to calculating other components of generator's variable costs in which it uses standard costs, such as fuel costs and operations and maintenance costs. In contrast, PJM allows market participants to submit their own calculations of generator greenhouse gas emission rates and allowance prices, but it also allows them to submit their own calculations of the other generator variable cost components, such as fuel costs and operations and maintenance costs.

Greenhouse gas allowance cost calculation

Under the California greenhouse gas cap program, market participants will have to surrender one greenhouse gas allowance for every 1,000 metric tons of CO_2 ($mtCO_2$) emitted by the generation under their control. The standard CO_2 emission rate for natural gas under U.S. Environmental Protection Agency and state regulations is 0.053165 $mtCO_2$/MMBtu.[17]

Using these values, the cost of greenhouse gas allowances could be incorporated into the various elements of generators' variable costs as follows:

- Incremental energy costs: Include greenhouse gas allowance costs as a per MWh incremental cost, which can be calculated as:

  Allowance cost per MWh =

  incremental CO_2 emissions per MWh ($mtCO_2$/MWh) * 1 allowance per $mtCO_2$ * greenhouse gas allowance price

  Where,

  Incremental CO_2 emissions per MWh ($mtCO_2$/MWh) = unit's incremental heat rate (MMBtu/MWh) * (0. 053165 $mtCO_2$/MMBtu)

- Minimum load energy costs: Include greenhouse gas allowance costs as a per MWh cost for a unit's minimum load output, which can be calculated as:

  Allowance cost per MWh =

  average CO_2 emissions per MWh at minimum load ($mtCO_2$/MWh) * 1 allowance per $mtCO_2$ * greenhouse gas allowance price

  Where,

  Average CO_2 emissions per MWh ($mtCO_2$/MWh) = unit's average heat rate at minimum load (MMBtu/MWh) * (0. 053165 $mtCO_2$/MMBtu)

- Start-up costs: include greenhouse gas allowance costs as a cost per start-up, which can be calculated as:

  Allowance cost per start-up =

[17] U.S. EPA Greenhouse Gas regulation, Subpart C, Table C-1 and C-2, http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=f095b41950528f0d4d3090382efcd1ce&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

CO2 emissions per start-up ($mtCO_2$/start-up) * 1 allowance per mtCO2 * greenhouse gas allowance price

Where,

CO2 emissions per start-up (mtCO2/start-up) = unit's start-up fuel requirement (MMBtu/start-up) * (0. 053165 mtCO2/MMBtu)

- Multi-stage generator transitions: include greenhouse gas allowance costs as a cost per transition, which can be calculated as:

  Allowance cost per transition =

  CO2 emissions per transition ($mtCO_2$/transition) * 1 allowance per mtCO2 * greenhouse gas allowance price

  Where,

  CO_2 emissions per transition ($mtCO_2$/transition) = unit's transition fuel requirement (MMBtu/transition) * (0. 053165 $mtCO_2$/MMBtu)

For all of the calculations described below, the ISO could use a documented greenhouse gas emission rate submitted by market participants for non-natural gas units and potentially for natural gas units if their actual emission rate varied for some reason from the standard rate.

In addition to the calculations above, there ISO could screen, using similar calculations, to determine if a generating unit emitted the 25,000 $mtCO_2$ annually needed to make it subject to the greenhouse gas cap regulations. These units would include small units or peakers that run infrequently. The ISO would not include greenhouse gas allowance costs in its calculation of variable costs for units that did not emit more than 25,000 $mtCO_2$ in the previous year. Market participants could provide justification to the ISO if they believed that a unit's emissions would exceed the minimum threshold in an upcoming year when in the previous year they did not.

Greenhouse gas allowance price

The ISO could determine the price of greenhouse gas allowances by using a published price index of the daily spot price of CO_2 allowances in the bilateral over-the counter market, similar to its existing methods for determining natural gas prices. This is the method the NYISO and ISO-NE use to determine the price of RGGI CO_2 allowances. PJM allows market participants to use either the spot price or their acquisition cost of allowances, but most reportedly use the spot price. The rationale for using the spot price of allowances is that it reflects the current cost of procuring an allowance, the replacement cost of using an allowance already held to generate, as well as the opportunity cost of not generating and selling the allowance.

Similar to the way that the ISO currently uses published natural gas prices for the various generator variable cost components it calculates, the ISO could determine greenhouse gas allowance prices as follows:

- Costs calculated daily: Use a published daily spot-market price.

- Costs calculated monthly (i.e. start-up and minimum load costs under registered cost option): Use the average of a published daily spot-market price over the first twenty days of each month to determine allowance costs to be used in the calculation of the registered costs to be fixed for the next month.

When calculating the CO_2 allowance costs to use for a one-month period under the registered cost option, using the average price over twenty days smoothes out any temporary price increases or decreases that may have occurred at the time of the monthly calculation. This avoids locking any temporary price changes into the calculation for an entire month. This is the similar to the method that the ISO currently uses to calculate natural gas prices used for start-up and minimum load costs under the registered cost option, which are also locked-in for a month. The difference is that the ISO currently uses natural gas futures prices for delivery in the next month, while the approach DMM is proposing here for greenhouse gas allowances averages each day's current spot price for greenhouse gas allowances. This difference is justified as natural gas spot and futures prices may diverge because natural gas storage is limited. Conversely, greenhouse gas spot market prices should correlate fairly well with futures prices.[18] For example, the spot prices should rise in the case of an anticipated future shortage, just as the futures prices would, because allowances purchased in the spot market can easily be retained in anticipation of a shortage. This has been the case for futures trading for RGGI carbon allowances, where futures prices for delivery in the current month are very close to futures prices for delivery at the end of the year.[19]

An alternative to using the spot market price of allowances would be to either use the market clearing prices from the quarterly auctions of greenhouse gas allowances that will be conducted by the Air Resources Board or the prices of bilateral trades reported in the Air Resources Board's market tracking system. However, neither of these methods would represent the current value of allowances. Auction prices would not capture price changes that occur between auctions. Prices of trades reported in the market tracking system may not accurately capture current prices because the trades are not reported until the buyer takes physical delivery, which may occur a significant period of time after the sale takes place.

Several providers produce price index services that are available by subscription that include California carbon allowance prices. It appears that these prices are based on surveys of brokers that trade carbon allowance forwards in the over-the-counter market.[20] In addition, forward contracts for California greenhouse gas allowances are traded on the Intercontinental Exchange (ICE), which publishes a daily summary of prices. The published prices for California greenhouse gas allowances all appear to be for delivery in December of each year. Conversely, if an index listing current spot prices is not developed, then the ISO could use the price of futures or forwards with the next upcoming delivery date.

[18] The futures price should differ from the spot market price by the risk-free interest rate to account for the purchaser of a future being able to defer payment until taking delivery.

[19] http://www.rggi.org/docs/MM_2010_Annual_Report.pdf, page 19.

[20] The term "over-the counter" refers to trades of financial products in which the counter-party is not one of the public exchanges. "Forward" contracts are sales contracts with delivery at a future date that are traded in the over-the-counter market. "Futures" contracts are sales contracts with delivery at a future date that are traded on one of the public exchanges and the parties to the contract are required to post financial assurance.