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Does California's CO_2 price affect wholesale electricity prices in the Western U.S.A.?

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Abstract

Using a sample of daily market data, we quantify the effect of California's CO_2 cap-and-trade program on the wholesale electricity prices of four interconnected market hubs in the Western U.S.A.: North of Path 15 (NP15) and South of Path 15 (SP15) in California, Mid-Columbia (Mid-C) in the Pacific Northwest, and Palo Verde (PV) in the Desert Southwest. A \$1/metric ton increase in California's CO_2 price is estimated to have increased the electricity prices by \$0.41/MWh (p-value < 0.0001) for NP15, \$0.59/MWh (p-value < 0.0001) for SP15, \$0.41/MWh (p-value = 0.0056) for Mid-C, and \$0.15/MWh (p-value = 0.0925) for PV. These estimates reflect: (a) the NP15 and SP15 sellers' pricing behavior of fully including the CO_2 price in their intra-state transactions; (b) the Mid-C price's 100% pass-through of the CO_2 price in the Pacific Northwest's hydro export to California; and (c) the statutory obligation of paying the CO_2 emissions cost by California's buyers of the electricity imported from the Desert Southwest. The policy implication is that internalization of CO_2's externality in the Western U.S.A. requires a cap-and-trade program with a regional scope that encompasses all four hubs, thereby remedying the California program's limited geographic coverage which introduces distortions in neighboring markets.

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1. Introduction

Growing concerns about climate change have led to transformations in the electricity industry in various parts of the world. These changes are partly driven by such policy instruments as the renewable portfolio standard (RPS) and cap and trade (C&T) programs that are designed to promote renewable energy development and reduce CO_2 emissions (Paul, et al., 2015; Trieu, et al., 2016). Implementing these programs helps achieve the international commitments of deep de-carbonization made at the 2015 "COP21" climate summit in Paris,[1] reinforced by the U.S.-China agreement ratified at the 2016 G20 summit held in Hangzhou, China.[2]

An RPS program mandates that a percentage target of electricity sales be met by qualifying renewable resources such as solar, wind or geothermal. For example, California has recently set a 50% target by 2030, extending the prior target of 33% by 2020. A load-serving-entity (LSE) such as a local distribution company (LDC) or an energy retailer may satisfy its RPS requirement by generating renewable energy or purchasing renewable energy credits (RECs) from renewable generators (del Río Gonzalez, 2007; Tsao et al., 2011; Delarue and Van den Bergh, 2016; Perez et al., 2016).

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[1] 21st Conference of Parties for implementing the United Nations Framework on Climate Change (UNFCCC), http://www.cop21paris.org/about/cop21/

[2] https://www.theguardian.com/environment/2016/sep/03/breakthrough-us-china-agree-ratify-paris-climate-change-deal

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A C&T program allocates tradable allowances that give polluters the right to emit by grandfathering, auction or both (Palmer and Burtraw, 2005; Palmer and Paul, 2015; Accordino and Rajagopol, 2015; Schmalensee and Stavins, 2015). The polluters then meet the C&T program's compliance requirements by surrendering a sufficient quantity of allowances to cover their CO_2 emissions. Thus, the program aims to improve economic efficiency by pursuing the first-best pricing rule that the marginal social benefit should equal the marginal social cost of electricity consumption (Woo et al., 2008; Varian, 1992).

While incentive-compatible with a firm's profit-maximizing behavior (Laffont and Tirole, 1993), these market-based RPS and C&T programs impact generators differently. An RPS program subsidizes renewable energy development by granting developers tradable RECs that can serve as a compliance instrument pursuant to a statutory target. In contrast, a C&T program penalizes polluting resources by enforcing emissions payments, rendering them less cost-competitive than clean resources such as solar and wind (Novan, 2015; Van den Bergh and Delarue, 2015; Gavard, 2016).

Several CO_2 C&T programs have been implemented at the regional and international levels. A notable example is the European Union Emission Trading System (EU ETS) that began its operation in 2005, currently covering the European

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Union's 31 member countries for CO_2 emissions from the electricity, energy-intensive industrial, and aviation sectors.

In contrast to the EU ETS, the two CO_2 C&T programs in the U.S.A. have less comprehensive geographic coverage. Specifically, the Regional Greenhouse Gas Initiative that began in 2009 is a joint effort by nine northeastern states to regulate CO_2 emissions from the electricity industry (Burtraw, et al., 2006; Hibbard, et al., 2015).

Established under Assembly Bill (AB) 32 - the California Global Warming Solutions Act of 2006 and administered by the California Air Resources Board (ARB), California's C&T program commenced operation on 01/01/2013, encompassing ~85% of greenhouse gas (GHG) emissions by large emitting entities in the state across all economic sectors (Schmalensee and Stavins, 2015).[3] AB32 mandates statewide GHG emissions be reduced to the 1990 levels by 2020. In August 2016, California passed Senate Bill 32 to extend AB32, establishing a new mandate of 40% reductions below the 1990 levels by 2030.[4]

California is an important case study of CO_2 C&T because it is the most populous state in the U.S.A. and the sixth largest economy in the world.[5] It operates a

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[3] http://www.arb.ca.gov/cc/capandtrade/guidance/cap_trade_overview.pdf

[4] http://www.latimes.com/politics/essential/la-pol-sac-essential-politics-updates-jerry-brown-california-climate-1472077480-htmlstory.html

[5] http://www.sacbee.com/news/business/article83780667.html

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C&T program within a large regional electricity market defined by the footprint of the Western Interconnection, a synchronous electric grid that covers parts of fourteen western states, two Canadian provinces, and one Mexican state. Thus, California presents a natural experiment for detecting a C&T program's effects on wholesale market prices at the in-state hubs subject to the requirement of CO_2 allowance surrender and those at the out-of-state hubs free from the same requirement.

There are recent simulation-based studies that assess the impact of the California C&T program on supply behavior, market prices and CO_2 emissions in the Western Interconnection (e.g., Chen et al., 2011; Limpaitoon et al., 2014; Bushnell et al., 2014; Thurber et al., 2015; Perez et al., 2016). Their foci include the equivalence of C&T differed by point-of-regulation (Chen et al., 2011), market power in C&T allowance market (Limpaitoon et al., 2014), market outcomes under the C&T program (Bushnell et al., 2014), interaction of RPS and C&T (Thurber etal., 2015), and efficiency of REC trading (Perez et al., 2016). To the best of our knowledge, however, there is no empirical analysis of market data to assess the California CO_2 C&T program's effect on the Western Interconnection's wholesale electricity prices. In comparison, the previous studies by Woo et al. (2014, 2016a, and 2016b) do not include the CO_2 price as one of the fundamental drivers of California's electricity prices, nor did the prior analyses of the Pacific Northwest's electricity prices (Woo et

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al., 2013, 2015). These regression studies' exclusion of the CO_2 price reflects: (a) their foci of the effects of nuclear plant shutdown and renewable energy development on electricity prices and generation investment incentives; and (b) their samples' limited variations in the CO_2 price data, posing an empirical challenge in isolating the CO_2 price's effect on electricity prices.[6] Nevertheless, this exclusion is a research deficiency that the current paper aims to amend.

This paper estimates the effects of California's CO_2 price ($/metric ton) on the wholesale electricity prices ($/MWh) at four electricity hubs in the Western U.S.A., which are considered as major pricing points by the U.S. Energy Information Administration (EIA). Linked by the Western Interconnection's major transmission paths, these hubs shown in Fig.1 are: North of Path 15 (NP15) in northern California, South of Path 15 (SP15) in southern California,[7] Mid-Columbia (Mid-C) in the Pacific Northwest, and Palo Verde (PV) in the Desert Southwest. Additional Western hubs include the California Oregon Border (COB), Mona in central Utah, Four Corners in northeastern Arizona and Mead in southern Nevada. These less actively

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[6] In the case of California, the focus of Woo et al. (2014) is the market price effects of renewable energy and nuclear plant shutdown. Its sample period is April 2010 – December 2012, which does not contain the CO_2 price data after the California C&T commencement date of 01/01/2013. The focus of Woo et al. (2016a) is the merit order effect of renewable energy development and the price divergence in California's day-ahead and real-time markets. Its sample period is 12/12/2012 – 04/30/2015, during which the daily CO_2 price data exhibit limited variations, as reflected by the sample mean = 12.51, standard deviation = 2.16 and coefficient of variation = 0.17. Finally, the focus of Woo et al. (2016b) is the *ex post* payoffs of natural-gas-fired generation based on the real-time market data for the same sample period. In the case of the Pacific Northwest, the focus of Woo et al. (2013, 2015) is the merit order effect of renewable energy development, not the CO_2 price effect on the Mid-C price.

[7] "Path 15 connects the transmission grids between northern and southern California and plays an important role in maintaining regional electric system reliability and market efficiency" (http://www.datcllc.com/projects/path-15/).

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traded hubs are excluded from our analysis because they are not considered by the EIA as major pricing points in the Western Interconnection. Moreover, the Mid-C price is highly correlated ($r > 0.9$) with the COB price, as is the PV price with the prices at Mona, Four Corners and Mead. These price correlations lend further support to our empirical focus on the Mid-C and PV hubs as the major pricing points outside of California.

This estimation is important and relevant to policy makers and market participants for several reasons. First, it shows whether the California hubs incorporate the CO_2 price, thereby encouraging the state's use of CO_2-free generation such as solar and wind to displace the in-state natural gas generation. Second, it shows whether the C&T program created a persistent markup of wholesale electricity prices, resulting in unanticipated income transfers from consumers to CO_2-emitting producers. Third, it reveals whether the California C&T program in the presence of inter-regional trading affects the wholesale electricity prices outside of California. Finally, it shows the financial impact on energy sellers within and outside of California, critical for the promotion of CO_2-free energy development.

Echoing our paper's real-world relevance is California's leading role in the fight against global warming.[8] The California C&T program's electricity price

8 http://www.nytimes.com/2016/12/26/us/california-climate-change-jerry-brown-donald-trump.html?_r=0

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consequences serve to inform the market effects that may come to other states in the Western Interconnection (e.g., Oregon and Washington) and the countries that already have or are considering C&T of CO_2 (e.g., Australia, New Zealand, Japan, Korea, India, and China).

Following Woo et al. (1997, 2013, 2014, 2015, 2016a, 2016b), our estimation is a regression analysis of the four hubs' daily electricity prices for the 65-month sample period of 01/01/2011 through 05/31/2016. As California's CO_2 trading commenced on 01/01/2013, the period has 24 pre-trading months and 41 post-trading months, yielding a large sample of ~1400 daily observations for detecting the CO_2 price's effects on wholesale electricity prices.

Our paper makes two main contributions to the literature on the empirical relationship between the CO_2 price and wholesale electricity prices. First, it documents that an increase in the CO_2 price tends to increase the bilaterally negotiated day-ahead heavy-load-hour (HLH) price for a working weekday's 16-hour period of 06:00-22:00. A \$1/metric ton increase in the CO_2 price is estimated to have increased the electricity prices by \$0.41/MWh (p-value < 0.0001) for NP15 and \$0.59/MWh (p-value < 0.0001) for SP15. Hence, we infer that the NP15 and SP15 prices fully embody the CO_2 price because Section 2.2.2 shows that the 100% pass-through of a \$1/metric ton increase in the CO_2 price is ~\$0.37/MWh for a

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combined cycle gas turbine (CCGT) and ~$0.48/MWh for a gas turbine (CT).

Second, it documents the first evidence based on ***actual*** market data that the CO_2 price's effect may extend beyond California's borders, thus underscoring inter-regional trading's important role in assessing the interconnected hubs' internalization of CO_2's externality (Chen et al., 2011; Tsao, et al., 2011; Thurber et al., 2015). Specifically, the Mid-C market price fully incorporates the CO_2 price because a $1/metric ton increase in the CO_2 price is estimated to increase the Mid-C price by $0.41/MWh ($p$-value < 0.0001). In contrast, the CO_2 price's marginal effect on the PV price is estimated to be $0.15/MWh ($p$-value = 0.0925), which is relatively small and statistically insignificant. This implies that California's policy of assigning responsibility for CO_2 emissions to the First Jurisdictional Deliverer (FJD) - the market participant that is responsible for importing electric energy into California, prevents California's CO_2 price from significantly influencing the price at Palo Verde.

Our empirical evidence's policy implication is that achieving CO_2's price-internalization under the first-best pricing rule in the Western U.S.A. requires a C&T program with a geographic scope that encompasses these four interconnected hubs. Further, implementation of CO_2 pricing in the Pacific Northwest states like Oregon and Washington that encompass the Mid-C trading hub is unlikely to significantly increase wholesale electricity prices, chiefly because those prices are

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already influenced by CO_2 pricing stemming from California's C&T program.

The paper proceeds as follows. Section 2 describes how California's CO_2 price may affect the Western Interconnection's electricity prices. It also presents the data sample that shapes our regression model. Section 3 reports the regression results, which are further discussed in Section 4. Section 5 concludes.

2. Material and methods

2.1 Background

There is a rich body of literature concerning various aspects of CO_2 C&T (e.g., del Río Gonzalez, 2007; Hintermann, et al., 2016; Martin et al, 2016). One issue that has attracted academic and policy attention is the extent of the CO_2 price's pass-through to wholesale electricity prices. This issue is important for two reasons. First, a C&T program may grant tradable permits to affected parties for free (grandfathering). If CO_2 emitting generators can pass the carbon cost to consumers through higher electricity prices, they earn windfall profits from a lump-sum subsidy from free permits and possibly larger gross margins. Second, the incidence of C&T is of great interest in public policy making. Had a C&T program disproportionally increased low-income households' electricity bills, a portion of the proceeds from auctioning CO_2 allowances could be redistributed via a subsidy scheme for these households.

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Theoretically, the CO_2 price's pass-through depends on a number of factors, including the price elasticities of supply and demand, market structure, and generation mixes (Sijm et al., 2006; Chen et al, 2008; Tsao et al., 2011; Fabra and Reguant, 2014; Hintermann et al., 2016). In particular, the pass-through is negatively (positively) related to the electricity market demand's (supply's) price responsiveness. If the electricity market *demand* is highly price-insensitive, the pass-through is expected to be close to 100%. In contrast, a highly price-insensitive electricity market *supply* likely results in a pass-through of close to 0%.

For an electrical system with thermal generation, less carbon-intensive resources may displace coal generation after the C&T program's implementation. The change in the system's resource mix's utilization increases the electricity price, so as to internalize the formerly unpriced CO_2 emissions. However, if the CO_2 price is low, the generation dispatch's merit order likely does not change, and the allowance cost simply functions as a tax on wholesale electricity purchases made by LSEs to meet their daily price-insensitive load obligations. The influence of market structure on the CO_2 price's effect is ambiguous, depending on whether the market demand curve is linear or double-log, as well as the market's number of sellers.

When estimating the extent of the CO_2 price's pass-through, researchers have used two approaches: simulation and regression. The simulation approach is an *ex*

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ante analysis, focusing on projecting market outcomes under varying assumptions on future supply-demand conditions. For example, the study by Chen et al. (2008) examines the pass-through and windfall profits at early phase of EU ETS, concluding that nearly all the windfall profits are associated with the lump-sum allowance rent through the initial allocation. The study by Wild et al. (2015) finds incomplete pass-through for the Australian National Energy Market, especially for the region with substantial hydro generation.

Due to its use of historical market data, a regression analysis is an *ex post* assessment of the CO_2 price's pass-through. Examples include: (a) Sijm et al. (2006), investigating the windfall profit in early stage of EU ETS; (b) Zachmann and Von Hirschhausen (2008), documenting that rising CO_2 prices of EU ETS permits have a stronger impact on wholesale electricity prices than falling CO_2 prices; (c) Fezzi and Bunn (2009), estimating that a 1% increase in the CO_2 price leads to a 0.32% increase in Europe's electricity prices; (d) Lo Prete and Norman (2013), identifying a statistically insignificant pass-through for the second phase of the EU ETS; (e) Fabra and Reguant (2014), finding an almost 100% pass-through in Spain; and (f) Hintermann (2016), estimating a pass-through of 84% to 104% in Germany. In sum, these regression studies do not present a consensus on the extent of the CO_2 price's pass-through in electricity prices. Further, they all use wholesale electricity price data

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for markets that are *all* subject to CO_2 C&T, unlike the four hubs considered herein.

2.2 The California cap-and-trade program

2.2.1 Program description

The California C&T program commenced operation on 01/01/2013 to achieve an overall 15% reduction in the state's GHG emissions to the 1990 levels by 2020. It covers electricity generators, large industrial facilities and distributors of natural gas and transportation fuels. The cap for 2013 is ~98% of the emissions level forecast for 2012. Its annual decline is ~2% in 2014 and ~3% for 2015 to 2020.

The C&T program allocates free allowances to large industrial facilities, with transitions to more auctions in later years. It also gives free allowances to electric and natural gas utilities, which must use the value of these allowances to benefit ratepayers and reduce GHG emissions.

Besides affecting California's in-state GHG emitters, the C&T program can impact electricity generators in other parts of the Western Interconnection. Under the ARB's FJD system, the state's electricity imports can come from (a) "unspecified" sources due to transactions where no specific generator is associated with the traded power; or (b) "specified" sources, where the source of the generation is identified and subject to unit-specific GHG emissions factors. Specified sources include all resources owned by or under long-term contract to California LSEs, as well as

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shorter-term imports from non-California entities with generation sources that have gone through the ARB process to become Specified. For Unspecified imports from wholesale market purchases whose original source is unknown or mixed, the ARB assigns a default emissions rate of 0.428 metric ton per MWh. In 2015, the ARB's GHG Emissions Inventory included 22.5 million tonnes of CO2 from Specified imports and 11.2 million tonnes from Unspecified imports.[9]

Most major Northwest hydro owners registered their resources with the ARB as Specified sources. The ARB Specified Source Facilities Workbook lists over 300 hydro facilities totaling 53 GW of capacity.[10] The ARB assigns a special status to Bonneville Power Administration (BPA) in the Pacific Northwest and BC Hydro in the Canadian province of British Columbia. While BPA and BC Hydro operate very large hydroelectric systems, they are prevented by statute from selling unit-specific power outside of their jurisdictional service areas. Hence, ARB has developed the "Asset-Controlling Suppliers" designation that reflects BPA's and BC Hydro's hydro-dominant resource portfolios.[11] This designation improves the profitability of BPA and BC Hydro's hydro export to California by eliminating the importers' need to procure CO_2 allowances under the FJD system.

Since California's LSEs must procure CO_2 allowances for their imports from

[9] https://www.arb.ca.gov/cc/inventory/data/data.htm
[10] https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/ghg-rep-power.htm
[11] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm

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the unspecified sources, they are unwilling to pay a CO_2 premium in their bilaterally negotiated prices in markets outside of California. Most of the power traded at the PV hub is sourced from thermal resources. As a result, we do not expect the California C&T program to materially increase the wholesale prices for electricity at the PV hub. However, much of the power traded in Pacific Northwest spot markets is sourced from surplus hydro, which qualifies as either Specified or ACS in California and for which California LSEs would indeed be willing to pay a premium. A point of inquiry for this analysis is, therefore, the degree to which California LSEs' willingness to pay a premium affects spot market prices at the Mid-C hub.

2.2.2 The cost-based benchmark

To develop the cost-based benchmark for the electricity price increase due to CO_2 C&T, we use *MC* to denote natural gas generation's marginal CO_2 emissions cost. As the California marginal generation's fuel in a working weekday's 16-hour period of 06:00-22:00 is natural gas (Woo et al., 2014, p.237), *MC* is the product of (a) the CO_2 price (\$/metric ton); (b) the CO_2 content of burning natural gas (= 0.053 metric ton/MMBtu);[12] and (c) the heat rate of a marginal natural gas generation unit, which is ~7 MMBtu/MWh for a CCGT and ~9 MMBtu/MWh for a CT (CEC, 2010).

Under an assumed 100% pass-through of *MC*, the electricity price's increase

[12] The U.S. EIA reports that the CO_2 content of burning natural gas is 117 pounds/MMBtu = 53 kg/MMBtu (https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11).

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due to a \$1/metric ton increase in the CO_2 price is ΔMC = ~\$0.37/MWh (= 0.053 $\times$ ~7) to ~\$0.48/MWh (= 0.053 $\times$ ~9). As a result, ΔMC is the cost-based benchmark for gauging the extent of the CO_2 price's pass-through to the electricity price. If the CO_2 price's estimated effect on the electricity price is not statistically different from ΔMC, it is considered to have been fully captured in the electricity price. Should the estimated effect be significantly below (above) ΔMC, the electricity price's pass-through of the CO_2 price would be seen as less (more) than 100%.

2.3. Data description

2.3.1. Why these four hubs?

We choose to study these hubs for three reasons. First, as shown in Fig.1, these hubs represent a broad geographic scope made possible by the Western Interconnection's vast transmission network. Second, they manifest the Western Interconnection's regional diversity in seasonal load patterns and generation fuel mixes, the primary source of inter-regional electricity trading's benefits (Orans et al., 2007). The third reason is data availability that enables an estimation of the CO_2 price's effects on the wholesale prices within and outside California's borders.

2.3.2 Source of electricity market price data

Our market price data come from SNL Financial (www.snl.com) and their availability dictates the setup of our regression analysis. We focus on the HLH prices

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because the SNL price data for electricity delivered outside the HLH period are often missing due to thin trading.

The day-ahead HLH price data are volume-weighted price indices based on the transactions voluntarily reported to SNL by traders who bilaterally negotiate the price and size terms of the Western Interconnection's standardized forward contract for a flat 16-hour block of electricity delivered in the next working weekday (Woo et al., 2013, 2015). For our four-hub analysis, price data comparability precludes the use of the NP15 and SP15 prices based on the California Independent System Operator's (CAISO's) hourly day-ahead and 5-minute real-time nodal prices determined by the CAISO's centralized least-cost dispatch of generation resources to reliably meet the California grid's nodal demands (Woo et al., 2014, 2016b).

2.3.3 Wholesale electricity price data

Table 1 presents the descriptive statistics of the data used in our regression analysis. Each price regression's left-hand-side variable is P_{jt}, the day-ahead HLH price for electricity delivered on day t in market j = 1 for NP15, 2 for SP15, 3 for Mid-C and 4 for PV. All stationary at the 5% significance level, these prices are highly volatile with large standard deviations and wide ranges. They exhibit contemporaneous correlations, presaging that the four interconnected hubs are integrated to form an aggregate market in the Western Interconnection (Woo et al.,

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1997).

2.3.4 Market integration hypothesis

We reason that if two hubs are integrated, their prices should not drift apart without limit (Woo et al., 1997). To explore if the market integration hypothesis (MIH) is empirically valid, we use OLS to estimate the following regression with random error ν_t:

$$D_t \quad = \quad \delta_0 + \delta_1 B_t + \nu_t,$$

where D_t = price difference between two hubs on delivery day t; and $B_t = 1$ if t is after the C&T program's start date, 0 otherwise. Thus, the expected price difference $E(D_t)$ before the C&T program's commencement is the average transmission cost δ_0. The C&T program's implementation alters $E(D_t)$ by δ_1, which measures the average difference between the two prices' pass-through of the CO_2 price.

For the MIH to be empirically valid, ν_t needs to be stationary. Hence, we apply the Phillips-Perron (PH) test for a unit root (Phillips and Perron, 1988) to determine if the OLS residuals of each of the six price difference regressions formed by the four price data series follow a random walk. The resulting PH test statistics are all highly significant (p-value < 0.0001), thus lending support to the MIH.

2.3.5 Fundamental drivers of wholesale prices

We assume the day-ahead NP15 and SP15 HLH prices move with their

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fundamental drivers listed in Table 1.[13] In addition to the CO_2 price which is our research focus, these drivers are chosen based on our prior research on the California market prices (Woo et al., 2014, 2016a, 2016b).

For proper chronological matching with the day-ahead HLH prices (Woo, et al., 2013, 2015), the drivers' values are daily day-ahead forecasts based on time series modeling (Weron, 2006) and produced by the stepwise autoregressive (STEPAR) method in PROC FORECAST of SAS (2004).[14] As a quick and automatic way to generate forecasts for many time series, the STEPAR method combines a "time trend regression with an autoregressive model and uses a stepwise method to select the lags to use for the autoregressive process" (SAS, 2004, p.835). In short, the drivers' day-ahead forecasts are automatically produced by PROC FORECAST *sans* additional modeling efforts by the authors.

At the 5% significance level, the PH test statistics suggest that all drivers' day-ahead forecasts are stationary, except for those of the CO_2 price, San Onofre nuclear plant's available capacity and natural gas price. Non-stationary regressors can

[13] Our data sources are as follows. The natural gas price data come from SNL (www.snl.com). The CAISO provides the data for the CO_2 price, system loads and solar and wind output (http://oasis.caiso.com/mrioasis/logon.do;jsessionid=5D9A2B355EF0330B4D1D9631157487E5). The nuclear capacity data are from the Nuclear Regulatory Commission (NRC) (http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/index.html). Finally, the U.S. Geological Survey (USGS) supplies the California hydro index (http://waterwatch.usgs.gov/index.php?r=ca&id=pa01d&sid=w__table2) and river discharge data http://waterdata.usgs.gov/ca/nwis/rt). The Klamath River's station is USGS 11530500 and the Sacramento River's station USGS 11447650.

[14] On 12/12/2012, the CAISO began publishing its day-ahead forecasts for system loads, solar energy and wind energy. These CAISO's forecasts are not used here because they are unavailable for our sample period's 23 pre-trading months of January 2011 to November 2012.

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cause misinterpretation of a regression's R^2 and t-statistics (Baffes, 1997). However, the regression results reported in Table 2 have the usual interpretation for two reasons. First, the daily CO_2 price forecasts for the 24 pre-C&T months are zero, and the San Onofre nuclear plant's capacity forecasts are also zero after the 01/31/2012 shutdown, implying that they resemble shifting dummy variables in our day-ahead price regressions.[15] Second, the daily natural gas price forecasts are found to be stationary at the less stringent 10% significance level, thus allaying the econometric concerns raised by Baffes (1997).

The first driver is C_t = daily forecast of the CO_2 price on day t. An increase in the CO_2 price is expected to increase the NP15 and SP15 prices, due chiefly to the state's marginal use of natural gas generation to meet the system demands in the HLH period.

The next driver is X_{1t} = daily forecast of the Henry Hub natural gas price (\$/MMBtu), which is highly correlated (r = ~0.9) with California's PG&E Citygate and SoCal Border prices. To avoid estimation bias, we use the exogenous Henry Hub price in our regression analysis because the PG&E Citygate and SoCal Border prices may be endogenous right-hand-side (RHS) variables in our electricity price

[15] Both variables' non-zero forecasts exhibit limited data dispersion. For the 01/01/2011 – 01/31/2012 period, the daily day-ahead forecasts for San Onofre plant's available capacity have a mean of 1816.0, a standard deviation of 623.0 with a coefficient of variation of 0.34. For the 01/01/2011 – 05/31/2016 period the daily day-ahead forecasts for the CO_2 price have a mean of 12.8, a standard deviation of 0.99 and a coefficient of variation of 0.08.

regressions (Woo et al., 2006). The natural gas price's coefficient measures the natural gas price's marginal effect on the electricity price. As a market-based marginal heat rate, it can readily be compared to a CCGT's and CT's heat rate to assess the empirical reasonableness of our regression results.[16]

There are two demand-related drivers for the HLH period on day t: X_{2t} = daily forecast of the load (average of hourly MWh) of Pacific Gas and Electric (PG&E), the largest LDC serving Northern California; and X_{3t} = daily forecast of the load of Southern California Edison (SCE), the largest LDC serving Southern California. According to the California Energy Commission, PG&E and SCE account for over 60% of the state's total electricity consumption.[17] We expect that increases in loads raise electricity prices due to the state's upward-sloping marginal generation cost curve (Woo et al., 2014).

The renewable energy drivers are X_{4t} = daily forecast of the wind output (average of hourly MWh) and X_{5t} = daily forecast of the solar output (average of

[16] To see this point, first consider a $1/MMBtu increase in the natural gas price that raises the electricity price by $\$\alpha_1$/MWh, as shown in Eq.(1) below. The coefficient α_1 has a heat rate (MMBtu/MWh) interpretation because $\$\alpha_1$/MWh = α_1 MMBtu/MWh $\times$ $1/MMBtu. Next consider a competitive electricity market's price that tracks the per MWh cost of the marginal generation unit. Suppose there is no capacity shortage so that the market price is P ($/MWh) and equal to the unit's short-run average cost AC. The marginal effect of the natural gas price G ($/MMBtu) on P is $\partial P/\partial G$ = ($\partial P/\partial AC$) ($\partial AC/\partial G$). Since $\partial P/\partial AC = 1$ and $\partial AC/\partial G$ = per MWh fuel requirement based on Shephard's Lemma (Varian, 1992, p.74), $\partial P/\partial G = \partial AC/\partial G = \alpha_1$ is a marginal market-based heat rate.

[17] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf; http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207438_20160115T152222_California_Energy_Demand_20162026_Revised_Electricity_Demand_Fo.pdf.

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hourly MWh) in the HLH period on day t. An increase in renewable output tends to reduce wholesale electricity prices via the well-documented merit order effect (Woo et al., 2014, 2016a, 2016b).

We use three variables to measure California's nuclear generation's availability: X_{6t} = daily forecast of the MW available at the 2160-MW Diablo Canyon nuclear plant in Northern California, X_{7t} = daily forecast of the MW available at the 2150-MW San Onofre nuclear plant in Southern California that was shut down on 01/31/2012, and X_{8t} = daily forecast of the MW available at the 4005-MW Palo Verde plant in Arizona, which is partially owned by SCE and other Southern California utilities.[18] Improved availability of nuclear capacities tends to lower electricity prices because nuclear generation is baseload, displacing resources with higher per MWh variable costs.

Because of California's substantial hydro resources (Woo et al., 2014, 2016a, 2016b), we use three hydro-related drivers for the daily HLH period: X_{9t} = daily forecast of the Klamath River's average discharge (000 ft^3 per second), X_{10t} = daily forecast of the Sacramento River's average discharge (000 ft^3 per second), and X_{11t} = daily forecast of California's hydro index (1 = driest, …, 7 = wettest). Improved hydro conditions expand the state's hydro generation capability, which tends to reduce the

[18] The California plants' size data are come from http://www.energy.ca.gov/nuclear/california.html; and the Palo Verde plant's from https://www.starsalliance.com/members/paloverde.php.

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state's electricity market prices.

The price correlations in Table 1 show that the day-ahead market prices are positively correlated with the day-ahead forecasts of the CO_2 price, the natural gas price and PG&E and SCE system loads, but are negatively correlated with the day-ahead forecasts of California's solar generation and hydro conditions. As some of the correlations (e.g., nuclear capacities available and wind energy) are at odds with our expectations, we propose a regression-based approach below to estimate the CO_2 price's effects.

2.4. Model

2.4.1. Causal relationships

Analytic tractability and data availability necessitate our assumptions of the following causal relationships: (a) the CO_2 price moves the NP15 and SP15 prices; (b) the NP15 price moves the Mid-C price; and (c) the SP15 price moves the PV price.

Assumption (a) is based on our prior studies of the fundamental drivers of the NP15 and SP15 prices (Woo et al., 2014, 2016a, 2016b). Assumptions (b) and (c) are based on Section 2.3.4 that shows these interconnected hubs form an aggregate market within the Western Interconnection. They also mirror the interregional price formation process in the Western Interconnection due to California's market size and import dependence, which was dramatically demonstrated during the Western

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electricity crisis of 2000-2001 (Woo, 2001, Woo et al., 2003).

Assumptions (b) and (c) greatly simplify our analysis. In particular, assumption (b) obviates the need of a detailed analysis of how the Mid-C price may move with its own fundamental drivers, as done by Woo et al. (2013, 2015). Assumption (c) circumvents the lack of information on some of the fundamental drivers of the PV price (e.g., system loads and renewable generation output). Whether assumptions (b) and (c) are reasonable is an empirical issue to be settled by our regression analysis. Had these assumptions been unreasonable, our regression results would have been empirically implausible, thus indicating the inconsistency between these assumptions and the market data.

2.4.2. Specification

We assume the data generating process (DGP) for the NP15 price is the following regression with random error ε_{1t} (Woo et al., 2014, 2016a, 2016b):

$$P_{1t} = \alpha_t + \alpha C_t + \Sigma_k \alpha_k X_{kt} + \varepsilon_{1t}, \quad (1)$$

where α_t = time-dependent intercept = linear function of the binary indicators for day-of-week and month-of-year. The linear regression given by Eq. (1) is chosen for its easy interpretation and empirical reasonableness measured by the goodness of fit and coefficient estimates' sizes and signs reported in Section 3.

The coefficient of primary interest is $\alpha > 0$, which is the marginal price effect

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of C_t. The remaining coefficients are (α_1, …, α_{11}), each measuring the marginal price effect of X_{kt} for $k = 1, \ldots, 11$. Our discussion of the fundamental drivers suggests $\alpha_k > 0$ if driver k is the natural gas price or system load. However, we expect $\alpha_k < 0$ when driver k is the solar or wind generation, the nuclear capacity available or a hydro condition.

The SP15 price's DGP is the following regression with random error ε_{2t}:

$$P_{2t} \quad = \quad \beta_t + \beta\, C_t + \Sigma_k\, \beta_k\, X_{kt} + \varepsilon_{2t}. \qquad (2)$$

Since Eq. (2) is totally analogous to Eq. (1), its discussion is omitted for brevity.

Our finding of electricity market integration in Section 2.3.4 implies that the Mid-C and NP15 prices move in tandem, so do the SP15 and PV prices. With random errors μ_t and η_t, the Mid-C and PV prices' DGPs under assumptions (b) and (c) in Section 2.4.1 are the respective regressions given below:

$$P_{3t} \quad = \quad \theta_t + \theta\, P_{1t} + \mu_t; \qquad (3)$$

$$P_{4t} \quad = \quad \gamma_t + \gamma\, P_{2t} + \eta_t; \qquad (4)$$

where θ_t and γ_t are time-dependent intercepts.

Using Eqs. (1) and (2) and defining random errors $\varepsilon_{3t} = (\varepsilon_{1t} + \mu_t)$ and $\varepsilon_{4t} = (\varepsilon_{2t} + \eta_t)$, we rewrite the Mid-C and PV price regressions as:

$$P_{3t} \quad = \quad \phi_t + \phi\, C_t + \Sigma_k\, \phi_k\, X_{kt} + \varepsilon_{3t}\,; \qquad (5)$$

$$P_{4t} \quad = \quad \psi_t + \psi\, C_t + \Sigma_k\, \psi_k\, X_{kt} + \varepsilon_{4t}. \qquad (6)$$

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Each coefficient in Eq. (5) is a combination of those in Eqs. (1) and (3). For example, $\phi_t = (\theta_t + \theta\,\alpha_t)$ is the time-dependent intercept in Eq. (5) and $\phi = \theta\,\alpha$ is the CO_2 price's effect on the Mid-C price. The same can be said about each coefficient in Eq. (6). As the RHS variables of Eqs. (5) and (6) are the drivers' day-ahead forecasts based on the autoregressive method, they are exogenous and do not cause the estimation bias attributable to endogenous RHS variables.

Using the iterated seemingly unrelated regressions (ITSUR) method in PROC MODEL of SAS (2004), we jointly estimate Eqs. (1), (2), (5) and (6) under the assumption that the random errors are contemporaneously correlated and follow a stationary AR(n) process.

The AR(n) assumption reflects that our market data are time series and that a random shock (e.g., a major facility outage) on day t-m for m = 1, …, n can impact the HLH prices on delivery day t. While n is not *a priori* known, we can empirically identify n based on the AR parameter estimates' sizes and statistical significance, as demonstrated in Section 3 below.

2.4.3 Testable hypotheses

To statistically determine the presence of the CO_2 price's pass-through, we test three hypotheses based on an economic theory of wholesale electricity trading among interconnected regions with diverse resource mixes. The theory's reference case is

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that prior to the California C&T program's 2013 commencement, the price difference between two interconnected hubs with competitive and active trading should reflect the transmission cost, as shown by the price difference regression described in Section 2.3.4 above.

After the program's commencement, California's in-state natural gas generators make competitive sell offers that incorporate the CO_2 price. Because hourly electricity demands are largely price-insensitive, the pass-through extent of the CO_2 price in the market prices is expected to be close to 100%. When the market structure is oligopolistic (Tishler, et al., 2008; Gal et al., 2017), the CO_2 price's pass-through may exceed 100% due to the electricity price markups above marginal costs. Hence, our first testable hypothesis is **H1**: $\alpha > 0$ and $\beta > 0$ so that the NP15 and SP15 prices contain a CO_2 premium equal to the price increase due to the California CO_2 C&T program's implementation.

While California importers are required by the C&T program to procure CO_2 allowances for their imported electricity, the ARB's stipulation of the hydro import's CO_2 content implies **H2:** $\phi > 0$ so that the Mid-C price contains a CO_2 premium. This hypothesis reflects that these hydro producers can obtain bilaterally negotiated prices that capture the C&T-induced price increase in California. It mirrors the opportunity costs (= revenues foregone) of these producers for not selling their hydro energy into

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the CAISO's day-ahead markets at the CAISO's day-ahead prices that contain a CO_2 premium.

Finally, the ARB's stipulation on the CO_2 content of California's non-hydro imports and requirement of allowance procurement for such imports lead to our third hypothesis **H3**: $\psi = 0$ so that the PV price does not contain a CO_2 premium. This hypothesis reflects California buyers' unwillingness to pay for an emission cost for electricity delivered to the PV hub by coal and natural gas generators.

3. Results

Table 2 presents our regression results. For brevity, it omits the coefficient estimates for the intercept and binary indicators for day of week and month of year. The adjusted R^2 values are between 0.72 and 0.85, suggesting our model's reasonable fit for our sample of noisy price data.

To see if Table 2 is empirically plausible, consider the AR(1) parameter estimates of 0.43 to 0.71 and the AR(2) parameter estimates of -0.02 to 0.17. Seven of the eight estimates are significant at the 5% level used in the rest of this paper, suggesting the declining impact of past shocks on the wholesale electricity prices.[19] Further, each price regression's sum of the AR parameter estimates is less than 0.71, thus allaying the concern of spurious regressions attributable to the random errors

[19] We have re-estimated the four price regressions under the AR(3) assumption, finding that AR(3) parameter estimates are close to zero, and the regression results are virtually unchanged.

following a random walk (Davidson and MacKinnon, 1993). Finally, while seven of the 48 coefficient estimates for the drivers have the wrong sign, they are small in size and insignificant (p-value > 0.10). All remaining coefficient estimates have signs consistent with our expectations.

We now turn our attention to the coefficient estimates of the fundamental drivers. The estimated effect of a $1/metric ton in the CO_2 price is $0.41/MWh ($p$-value < 0.0001) for NP15 and $0.59/MWh ($p$-value < 0.0001) for SP15, lending support to **H1**: $\alpha > 0$ and $\beta > 0$. As their standard errors are 0.0842 for NP15 and 0.0817 for SP15, these estimates are not statistically different from ΔMC, the cost-based benchmark of $~0.37/MWh to ~$0.48/MWh established in Section 2.2.2. Thus, the California electricity prices fully embody the CO_2 price.[20]

The CO_2 price's estimated effect on the Mid-C price is $0.41/MWh ($p$-value = 0.0056), thus supporting **H2**: $\phi > 0$. While not statistically different ΔMC because its standard error is 0.1396, this estimate is the same as the NP15 estimate reported above, thereby indicating the remarkably close relationship between the Mid-C and NP15 CO_2 premiums.

The CO_2 price's estimated impact on the PV price is $0.15/MWh and

[20] The CO_2 price's estimated marginal effect on the SP15 price is $0.18/MWh (= $0.59/MWh - $0.41/MWh) larger than the one for the NP15 price. We use the Wald test as part of our ITSUR estimation to determine that the estimated price difference is statistically significant (p-value < 0.01), implying that the SP15 zone had marginal generation units with higher CO_2 emissions rates than the NP15 zone in our sample period. We attribute this finding to the loss of the San Onofre nuclear plant that led to increased utilization of aging and less fuel-efficient generation units in the SP15 zone during this sample period.

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insignificant (p-value = 0.0925), implying that we cannot reject **H3**: $\psi = 0$. As the ψ estimate's standard errors is 0.0871, the upper bound of the 95% confidence interval of ψ is \$0.317/MWh, below the benchmark of \$0.428/MWh for imports from "unspecified" generation units in the Desert Southwest. Hence, the PV price's CO_2 premium estimate sharply contrasts those for the Mid-C, NP15 and SP15 prices.

For the remaining drivers, we find:

- A \$1/MMBtu increase in the natural gas price tends to raise the NP15 price by \$7.38/MWh, the SP15 price \$7.48/MWh, the Mid-C price \$7.43/MWh, and the PV price \$6.66/MWh. As the estimated electricity price increases per dollar increase in the natural gas price are the market-based heat rate estimates, they are closer to a CCGT's heat rate of ~7 MMBtu/MWh than a CT's heat rate of ~9 MMBtu/MWh. Hence, traders in their day-ahead negotiations anticipate that the marginal generation unit in the HLH period is more likely a CCGT than a CT, as suggested by the discussion of California's marginal generation technology in Woo et al. (2014, p.237).
- Rising system loads tend to raise the market prices, reflecting that they are met by resources with increasingly high fuel costs.
- Renewable energy is found to have merit order effects because an increase in California's wind and solar output tends to reduce the NP15 and SP15 prices,

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more so than the Mid-C and PV price.[21]

- An increase in the daily nuclear capacities available tends to reduce the market prices, reflecting their displacement of natural gas generation.
- The coefficient estimates for the hydro variables imply that lower California hydro availability tends to raise the NP15 and SP15 prices, which in turn can increase the Mid-C and PV prices.

In summary, Table 2 paints a reasonable picture of the price data's DGP for the four hubs, yielding eminently plausible estimates for the CO_2 price's effects on these hubs' HLH prices.

4. Discussion

The CO_2 price's estimated effects on the NP15 and SP15 prices reflect that the California prices fully capture the CO_2 price. A policy question of immediate concern is the C&T program's relative bill impacts. To answer this question, we use the CO_2 price's estimated coefficient of 0.41 for NP15 and 0.59 for SP15 to perform a counter-factual calculation, which would not have been possible *sans* the regression results in Table 2.

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[21] An insightful reviewer remarks that some of these estimated merit order effects are an order of magnitude smaller than the estimated price impacts of system loads. Hence, they contradict the finding of zero net load effects in Woo et al. (2016b, Table 4). A plausible explanation is as follows. The regression analysis by Woo et al. (2016b) uses the CAISO's centrally determined prices which recognize the offsetting impacts of renewable generation and system loads. Bilateral price negotiations among traders, however, are more driven by the predictable system loads than the hard-to-forecast renewable generation. This is because while traders can accurately forecast the delivery day's system loads based on readily available weather forecasts, they are incapable in making similarly accurate day-ahead forecasts of solar and wind generation.

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For 2015, the average of the daily HLH price is \$36.0/MWh for the NP15 hub and \$38.63/MWh for the SP15 hub. The average daily CO_2 prices is \$13.0/metric ton. Absent the California C&T program, the NP15 price would have been lower by \$5.33/MWh (= 13 × 0.41) and the SP15 price \$7.67/MWh (= 13 × 0.59). Thus, the program could have increased the average NP15 price in 2015 by 17.4% (= [36.0 / (36.0 – 5.33)] – 1) and the SP15 price 24.8% (= [38.63 / (38.63 – 7.67)] – 1). The program's expected bill impacts on end-use customers are no more than 13% because PG&E's and SCE's tariffs indicate that the average generation procurement costs are approximately half of these two LDCs' average retail rates. These expected impacts, however, ignore the C&T program's "revenue recycling" that reduce end-users' bills through free allocation of CO_2 allowances to LSEs. Further, California LSEs procure renewable energy through long-term power purchase agreements whose price is determined outside of the wholesale energy. Thus, the impact of the C&T program on end-users' bills cannot be fully determined through an analysis of wholesale prices alone.

California LSEs import from both specified and unspecified sources.[22] For unspecified sources, California importers are required to surrender the necessary CO_2 emissions allowances at 0.428 metric tons per MWh. This raises two related questions:

[22] http://energy.ca.gov/almanac/electricity_data/total_system_power.html

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(1) what explains the statistically significant CO_2 premium estimate in the Mid-C price? and (2) what explains the statistically insignificant CO_2 premium estimate in the PV price?

To answer the first question, consider the kind of transactions that occur at the Mid-C hub, the major interconnection point of transmission lines owned by BPA, Chelan Public Utility District, Douglas Public Utility District, and Grant Public Utility District. The Mid-Columbia area is home to several very large hydroelectric projects totaling over 14,000 MW,[23] owned by the U.S. federal government and three Mid-Columbia Public Utilities Districts: (1) Grand Coulee (U.S. Bureau of Reclamation, 3765 MW); (2) Chief Joseph (U.S. Army Corps of Engineers, 2614 MW); (3) Rocky Reach (Chelan County PUD, 1300 MW), Wanapum (Grant County PUD, 1092 MW); (4) Priest Rapids (Grant County PUD, 956 MW); (5) Wells (Douglas County PUD, 840 MW); and (6) Rock Island (Chelan County PUD, 629 MW). In addition, other hydro owners such as Puget Sound Energy, Avista, Seattle City Light, and Powerex (power marketing subsidiary of BC Hydro) trade at Mid-C. These hydro owners have hydro storage capabilities that have historically been used to daily import energy at the relatively non-HLH low prices and resell the stored energy at the relatively high HLH prices.

[23] https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/ghg-rep-power.htm; https://www.bpa.gov/power/pgf/hydrpnw.shtml; https://www.chelanpud.org/, http://www.grantpud.org/, http://www.douglaspud.org/wells-project

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With the additional incentive created by the California C&T program, these hydro owners may increase their HLH exports of specified CO_2-free power to California. The increase in exports to California would, except during the rare instances of hydro spill, result in increased natural gas generation in the Northwest, needed to make up for the loss of exported hydropower.[24] Thus, one effect of California's C&T program is increased natural gas generation in the Pacific Northwest.

As all HLH hydro sales can be exported to California at the NP15 price that contains a CO_2 premium, these hydro owners' opportunity cost is the NP15 price net of the transmission cost, the basis for their willingness to accept for their Mid-C HLH sales. While non-California LSEs are not required to surrender CO_2 emissions allowances and hence unwilling to pay for a CO_2 premium, they cannot buy Mid-C HLH electricity at a price below the hydro owners' opportunity cost that includes the NP15 price's CO_2 premium.

To answer the second question, consider the kind of transactions occurred at the PV hub, the major interconnection point at the Palo Verde nuclear plant. Most of the HLH transactions come from thermal generation. As a result, the opportunity cost

[24] Based on E3's 20+ years of working relationship with the Pacific Northwest generators, BC Hydro, BPA and other hydro owners have always been selling all of their surplus hydro not needed to reliably serve their domestic load obligations. Such surplus hydro is available in a typical hydro year because these hydro owners plan their systems under the assumption of an extremely dry hydro year. Verified by E3's production simulation results done for BPA and other clients in the Western Interconnection, selling additional hydro export beyond the pre-C&T levels is made possible by natural gas generation built to meet the regional resource adequacy and operation reliability requirements.

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for energy traded at the PV hub is the SP15 price net of the transmission cost and CO_2 premium. To be sure, a thermal generator may want to sell at the Mid-C price that has a CO_2 premium. However, Fig.2 shows that besides the Pacific Intertie that interconnects Washington, Oregon and California, the transmission capacity between the Desert Southwest and Pacific Northwest is very limited. Hence, the Desert Southwest - Pacific Northwest transaction likely uses the Pacific Intertie through California, thus triggering the CO_2 emissions allowance requirement under the FJD provision. This explains why the CO_2 price's effect on the PV price is moderately positive but statistically insignificant.

5. Conclusions and policy implications

Using a large sample of daily data for the 65-month period of 01/01/2011 – 05/31/2016, we document statistically significant (p-value < 0.05) estimated effects of the CO_2 price on the NP15, SP15 and Mid-C prices. For a $1/metric ton increase in the CO_2 price, these estimated effects are $0.41/MWh to $0.59/MWh, which are not statistically different from the cost-based benchmark of ~$0.37/MWh to ~$0.48/MWh at an assumed 100% pass-through rate. For the PV price, the estimated effect is $0.15/MWh and statistically insignificant.

The overall conclusion of our findings is that full price-internalization of CO_2 emissions in the Western U.S.A. in pursuance of the first-best pricing rule would

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require a C&T program to encompass all four hubs, thereby remedying the California program's inadequate geographic coverage. If adopted, such a program would likely raise the PV price. However, due to the effects of the ARB's rules regarding the Pacific Northwest hydro, broadening the California C&T program would not have a discernable impact on the Mid-C price.

Our findings have the following policy implications. First, market participants who sell at Mid-C likely realize a windfall profit due to California's C&T program. By reserving and scheduling over transmission capacity on the California-Oregon Intertie, specified hydro generators in the Pacific Northwest can export at electricity prices with a CO_2 premium. This ability increases the negotiated price at which they are willing to sell or California buyers' willingness to buy in the Mid-C market.

Second, because there is no CO_2 allowance surrender obligation associated with Mid-C power deliveries, the CO_2 premium presents a windfall gain to owners of coal and natural gas generation in addition to the hydro owners, contrary to the C&T program's purpose to primarily provide financial incentives to clean energy sources.

Third, the second author's least-cost production simulations which include the CO_2 price's impact on generators show that the likely physical effect of the ARB rules regarding the Pacific Northwest hydro generation under a C&T policy is an increase natural gas generation in the Pacific Northwest and a reduction of similar size in

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California or the Desert Southwest. This is because after the C&T program's commencement, owners of hydro generation in the Pacific Northwest export more electricity into California, thus reducing California's reliance on in-state natural gas generators or import of natural gas generation from the Desert Southwest. To enable an increase in hydro exports to California, natural gas generation increases in the Pacific Northwest. As a result, the overall reduction in the Western Interconnection's CO_2 emissions due to additional hydro exports to California is likely to be small.[25]

Taken together, the aforementioned policy implications reinforce that a C&T program covering only a portion of a large integrated electricity market with interconnected hubs results in market distortions and unintended consequences. This is underscored by our empirical evidence that expanding the California's C&T program's geographic scope would improve its effectiveness in reducing the CO_2 emissions in the entire Western Interconnection, without the unintended windfall gains of non-hydro generators outside of California.

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[25] To further elaborate this finding, suppose the natural gas generation increase in the Pacific Northwest is A MWh, which enables a hydro export increase, beyond the region's surplus hydro export in the absence of the California C&T program. As a result, this incremental hydro export displaces the marginal natural gas generation in California and the Desert Southwest. The Pacific Northwest's increase in CO_2 emissions is $Z_1 = A\,M\,X$, where M = natural gas' carbon content of 0.053 metric ton per MMBtu and X = marginal heat rate in the Pacific Northwest. The decrease in CO_2 emissions in California and the Desert Southwest is $Z_2 = (1 - L)\,A\,M\,Y$, where L = marginal transmission loss for the Pacific Northwest's A MWh export and Y = marginal heat rate in California and the Desert Southwest. The change in the Western Interconnection's overall CO_2 emissions is $\Delta = Z_1 - Z_2 = M\,[A\,(X - Y) + L\,A\,Y]$. The second author's least-cost production simulation results for the entire Western Interconnection indicate $X \approx Y$, thus implying $M\,A\,(X - Y) \approx 0$ and $\Delta \approx M\,L\,A\,Y > 0$.

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Finally, we would be remiss had we failed to remark that when pursuing their own GHG reduction programs, Washington and Oregon should be mindful of how the electricity price in the Pacific Northwest is already affected by California's C&T program. In particular, a Washington-Oregon C&T program may have little impact on the CO_2 emissions in these states, unless this program's CO_2 price would raise the Mid-C price beyond its current pass-through of the California CO_2 price.

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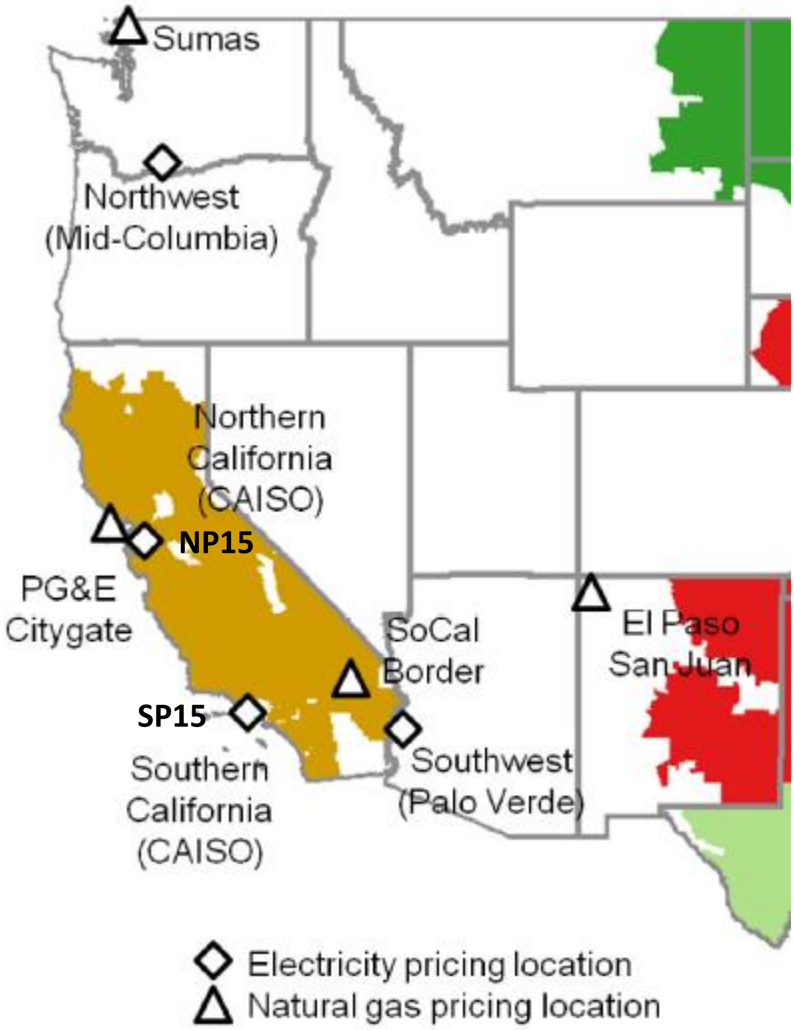

Fig.1. Major pricing locations in the Western Interconnection (Source: https://www.eia.gov/electricity/monthly/update/wholesale_markets.cfm#tabs_wh_price-3)

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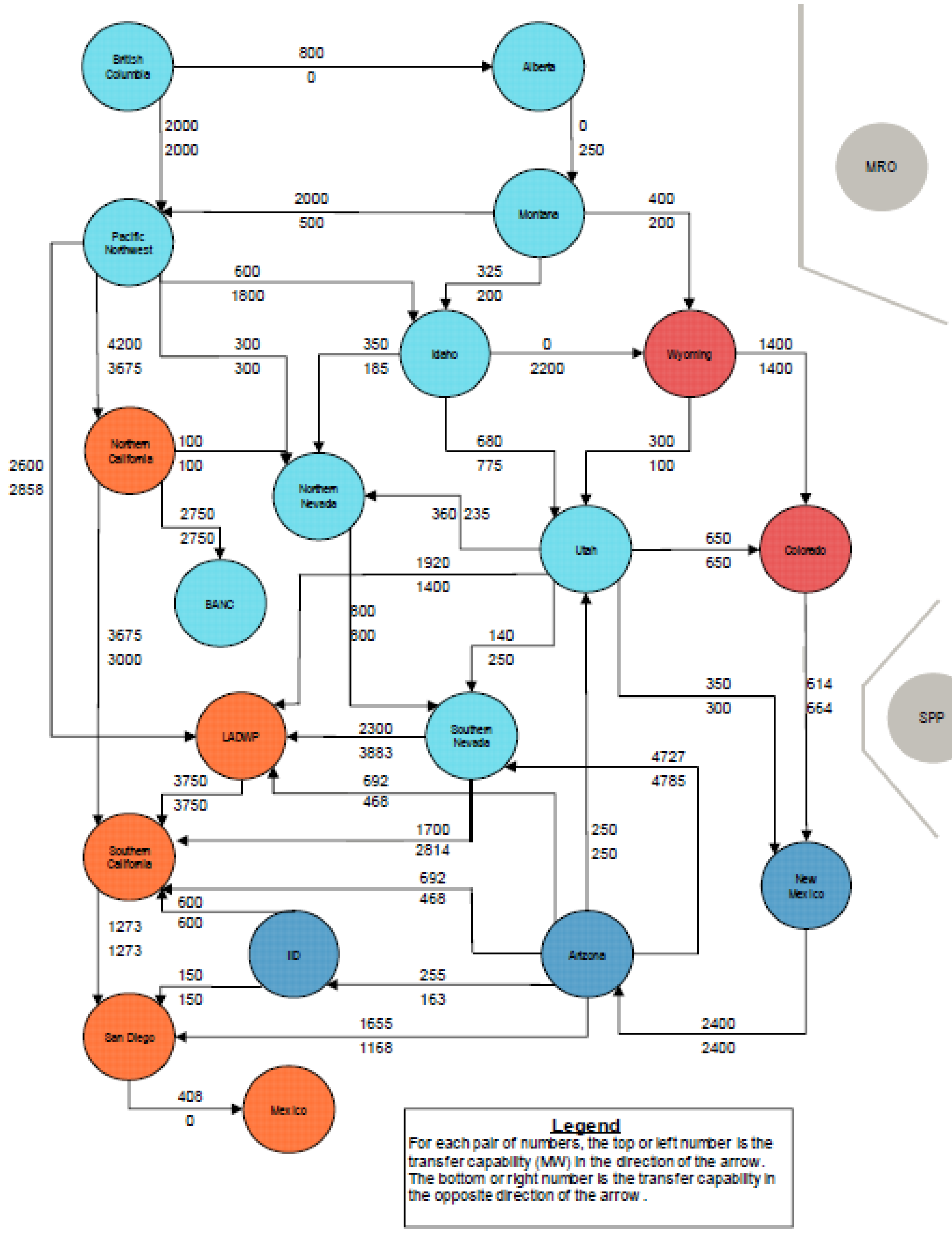

Fig.2. The Western Interconnection's transmission transfer capacity (MW) in 2016 (Source: https://www.wecc.biz/Reliability/2016PSA_Final.pdf)

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Table 1. Descriptive statistics for the metric variables in the sample period of 01/01/2011 – 05/31/2016

Variable	Mean	Standard deviation	Minimum	Maximum	Price correlation			
					NP15	SP15	Mid-C	PV
P_{1t}: NP15 HLH price ($/MWh)	38.94	10.78	16.00	175.00	1	0.942	0.820	0.863
P_{2t}: SP15 HLH price ($/MWh)	40.23	11.32	14.50	161.50	0.942	1	0.781	0.869
P_{3t}: Mid-C HLH price ($/MWh)	29.70	13.38	0.50	218.00	0.820	0.781	1	0.799
P_{4t}: PV HLH price ($/MWh)	33.46	10.16	14.86	171.50	0.863	0.869	0.799	1
C_t: California CO_2 price ($/metric ton)	8.05	6.24	0.0	16.39	0.312	0.259	0.189	0.020
X_{1t}: Henry Hub price ($/MMBTU)	3.37	0.90	1.52	8.37	0.687	0.703	0.543	0.716
X_{2t}: PG&E HLH load (average of hourly MWh)	13200.0	1297.0	11054.0	17608.0	0.266	0.306	0.292	0.435
X_{3t}: SCE HLH load (average of hourly MWh)	13347.0	1739.0	10581.0	19498.0	0.278	0.335	0.254	0.422
X_{4t}: California HLH wind (average of hourly MWh)	1190.0	547.12	189.63	2932.0	***0.066***	***0.041***	***0.018***	***0.039***
X_{5t}: California HLH solar (average of hourly MWh)	1275.0	1049.0	-384.47	4410.0	***0.010***	-0.132	-0.069	-0.204
X_{6t}: MW available at the Diablo Canyon nuclear plant	1954.0	389.22	176.56	2264.0	-0.040	-0.086	***0.057***	-0.032
X_{7t}: MW available at the San Onofre nuclear plant	358.57	774.18	0	2139.0	-0.123	-0.120	-0.005	***0.137***
X_{8t}: MW available at Palo Verde nuclear plant	3666.0	558.38	1360.0	4114.0	***0.003***	***0.038***	***0.003***	***0.055***
X_{9t}: Klamath River's HLH discharge (000 ft^3/second)	13.82	14.27	2.78	113.83	-0.378	-0.357	-0.345	-0.356
X_{10t}: Sacramento River's HLH discharge (000 ft^3/second)	17.26	13.36	3.75	84.83	-0.287	-0.233	-0.199	-0.120
X_{11t}: California hydro index (1 = driest, …, 7 = wettest)	3.60	0.66	1.28	5.29	-0.331	-0.236	-0.206	-0.051

Note: For proper chronological matching with the price data, the fundamental drivers' values are day-ahead forecasts produced by PROC FORECAST (SAS, 2004). Since the San Onofre plant was shut down on 01/31/2012, its post-shut-down MW available is zero. Price correlation coefficients in ***italic*** are contrary to our expecations.

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Table 2. ITSUR regression results for the wholesale electricity prices in the four trading hubs in Western U.S.A. for the sample period of 01/01/2011 – 05/31/2016

Variable	Eq. (1): P_{1t} = NP15 HLH price			Eq. (2): P_{2t} = SP15 HLH price			Eq. (5): P_{3t} = Mid-C HLH price			Eq. (6): P_{4t} = PV HLH price		
	Estimate	Standard error	*p*-value	Estimate	Standard error	*p*-value	Estimate	Standard error	*p*-value	Estimate	Standard error	*p*-value
Adjusted R^2	0.8052			0.8508			0.7246			0.7807		
AR(1) parameter	0.4300	0.0181	<.0001	0.5702	0.0191	<.0001	0.7105	0.0211	<.0001	0.5147	0.0187	<.0001
AR(2) parameter	0.1730	0.0174	<.0001	0.0585	0.0180	0.0012	-0.0252	0.0209	0.2290	0.1036	0.0183	<.0001
C_t: California CO_2 price ($/metric ton)	**0.4104**	0.0842	<.0001	**0.5927**	0.0817	<.0001	**0.4126**	0.1486	0.0056	0.1466	0.0871	0.0925
X_{1t}: Henry Hub natural gas price ($/MMBtu)	**7.3862**	0.4012	<.0001	**7.4801**	0.3845	<.0001	**7.4306**	0.6724	<.0001	**6.6582**	0.4096	<.0001
X_{2t}: PG&E HLH load (average of hourly MWh)	**0.0017**	0.0003	<.0001	**0.0009**	0.0003	0.0058	**0.0023**	0.0005	<.0001	**0.0011**	0.0003	0.0011
X_{3t}: SCE HLH load (average of hourly MWh)	**0.0007**	0.0002	0.0028	**0.0011**	0.0002	<.0001	***-0.0004***	0.0004	0.2949	**0.0006**	0.0002	0.0079
X_{4t}: California HLH wind output (average of hourly MWh)	-0.0006	0.0004	0.1248	**-0.0008**	0.0003	0.0128	***0.0007***	0.0005	0.1571	-0.0002	0.0004	0.6411
X_{5t}: California HLH solar output (average of hourly MWh)	-0.0005	0.0005	0.2778	**-0.0026**	0.0004	<.0001	-0.0014	0.0008	0.0767	**-0.0012**	0.0005	0.0132
X_{6t}: MW available at the Diablo Canyon nuclear plant	**-0.0017**	0.0007	0.0104	**-0.0022**	0.0006	0.0007	***0.0003***	0.0011	0.7738	-0.0013	0.0007	0.0551
X_{7t}: MW available at the San Onofre nuclear plant	**-0.0016**	0.0006	0.0088	**-0.0032**	0.0006	<.0001	***0.0001***	0.0011	0.9376	-0.0004	0.0006	0.4714
X_{8t}: MW available at the Palo Verde nuclear plant	-0.0005	0.0005	0.3295	-0.0003	0.0005	0.5760	-0.0011	0.0008	0.1817	-0.0005	0.0005	0.3757
X_{9t}: Klamath River's HLH discharge (000 ft^3/second)	-0.0137	0.0222	0.5370	-0.0381	0.0210	0.0702	-0.0017	0.0345	0.9606	-0.0284	0.0228	0.2126
X_{10t}: Sacramento River's HLH discharge (000 ft^3/second)	-0.0041	0.0284	0.8852	***0.0107***	0.0272	0.6947	***0.0090***	0.0460	0.8446	***0.0151***	0.0292	0.6054
X_{11t}: California hydro index (1 = driest, …, 7 = wettest)	**-2.1255**	0.7022	0.0025	-0.4769	0.6597	0.4699	**-2.8871**	1.0897	0.0082	-0.7916	0.7159	0.2691

Note: Omitted here for brevity are the estimates for the intercept and binary indictors for day-of-week and month-of-year. The coefficient estimates in **bold** for the fundamental drivers' forecasts have the correct sign and are significant at the 5% level; those in ***italic*** have the wrong sign but are insignificant at the 5% level.