Regulatory Barriers to Lowering the Carbon Content of Energy Services

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This document compiles a list of state and local regulatory barriers to greater penetration of technologies and mechanisms that reduce the carbon content of the energy services consumed in the United States. A preliminary list of regulatory barriers is given below.

1. *Transmission planning and expansion approval process.* A comprehensive national transmission planning process is necessary to support the large-scale deployment of renewable energy resources. The two major interconnected grids in the United States—the Eastern Interconnection and the Western Interconnection should have a regional transmission planning and siting process that also constructs and pays for each interconnection's transmission network at the regional level.

    a. The geographic distribution of renewable energy resource areas in the United States implies that the least-cost approach to meeting state-level and national renewable energy mandates would be to construct wind, solar, and geothermal resources in sparsely populated states far from the major load centers. This emphasizes the need for multi-state transmission planning process that can mandate inter-state siting and construction of transmission lines, or at least bundle proposed transmission projects together to

Any "clean energy" initiative cannot be effective without prompt commercialization of new technologies that are funded by both the public and private sectors. All commercial activities are affected by the prevailing legal environment. The energy sector is unusually subject to multiple federal, state, and local regulations that affect both the development of new technologies and the pace at which they can be rolled out.

At the request of the Ewing Marion Kauffman Foundation, one of the nation's leading energy economists, Frank Wolak of Stanford University, provides a useful inventory of regulatory barriers (primarily at the state level) that inhibit the commercialization of technologies that would lower the carbon content of energy services consumed in the United States. A preliminary list of regulatory barriers is given in this paper.

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obtain a regional transmission plan that all of the states find acceptable. According to the National Renewable Energy Laboratory (NREL), Montana has almost 30 times potential wind energy that California has despite having approximately 1/40 of the population of California. There are many other sparsely populated states with significant wind resources in both the Western and Eastern Interconnection. For example, both North and South Dakota have enormous wind resources relative to their populations.

b. The Public Utility Commission of Texas currently manages the transmission planning process for the Electric Reliability Council of Texas (ERCOT), the remaining United States grid. Texas is also the largest wind producing state in spite of not currently being interconnected with the rest of the United States. Although Texas also has the nation's largest state-level wind resource potential, having a single entity overseeing the transmission planning process for all of ERCOT has fostered the rapid growth in wind generation in the state. In contrast, states in the Eastern and Western Interconnections must currently coordinate their transmission planning processes among multiple public utilities commissions, which has limited the efficient development of wind resources in these interconnections.

c. There is currently no federal right-of-way for siting transmission network expansions. Both sides of a proposed interstate transmission line must approve of the project for it to be built. This fact makes it very difficult to site and construct interstate transmission lines because the electricity is typically leaving a low-price area and being sold in high-price area, and the transmission expansion is very likely to increase the price in the low-price area. The recent Palo Verde Devers 2 line designed to bring electricity from Arizona into southern California is an example of this phenomenon. Even with Energy Policy Act (EPA Act) of 2005 Section 1221 national interest electric transmission corridor process Southern California Edison, the sponsor of the line, was unable to overcome the Arizona Corporation Commission's opposition to the line.

d. Most state-level regulatory processes for determining whether a project has expected benefits in excess of expected costs typically only consider the benefits to the ratepayers of the utility undertaking the transmission upgrade in spite of the fact that upgrade may yield enormous economic benefits to customers in other states or utility service territories because of the interconnected nature of the high-voltage transmission network in the

Western and Eastern Interconnections. This utility-specific benefit-cost criterion even exists in multi-utility jurisdictions with formal wholesale markets.

e. Virtually all state-level renewable portfolio standards (RPS) that mandate a certain fraction of a utility's wholesale electricity purchases must come from renewable sources by a pre-specified future date are all far behind achieving these targets because of inadequate transmission infrastructure to allow renewable energy facilities to interconnect and deliver electricity to load centers. Even if a generation unit could be constructed where the renewable resource was located and connected to the high-voltage transmission network, it would often be constrained-off because of inadequate transmission out of the renewable resource region to the major load centers. For example, McCamey, the "Wind Energy Capital of Texas," faced this problem before significant transmission expansions from West Texas to the major East Texas load centers were completed.

2. *Transmission pricing*. A simplified, standardized, and interconnection-wide approach to transmission pricing is needed to facilitate the siting and construction of transmission projects to support the large scale deployment of renewable energy.

   a. There are large differences across states in how transmission projects are paid for. Some assign the legal liability to loads, others split it between generation unit owners and loads, and others assign it to generation unit owners. Some standardization in how transmission projects are paid for would facilitate the interstate transmission capacity needed to support large-scale renewable energy deployment.

   b. The principles of "cost causation" and "beneficiary pays" are often invoked by parties to the regulatory process to justify many approaches to transmission pricing. However, it is extremely difficult to determine precisely which entities caused the need for a specific transmission expansion and how much each of them benefitted from the transmission expansion. Consequently, the pursuit of these worthy but very difficult-to-attain goals in the transmission planning and pricing process can cause many socially beneficial projects to be rejected by the transmission planning process.

   c. The economies to scale in constructing transmission facilities relative to the size of many renewable energy projects argue in favor of building large transmission projects, much larger than the typical size of a renewable energy project, to major renewable resource centers. Given the ambitious renewable energy goals in many parts of the United States, building the transmission facilities needed to access the entire renewable resource, rather than building incremental transmission facilities with each new renewable energy project at that location, can result in significant long-term savings in transmission network costs to electricity consumers. However, constructing a large transmission project in anticipation of future renewable investment creates a mismatch between the revenue stream needed to pay for the transmission project and the revenue stream that existing renewable resource owners can pay that must be addressed through the transmission pricing process.

d. The existing approach transmission network owners use to gain access to the right-of-way on a property make it unattractive for landowners to have a transmission line on their land. More creative contracting schemes that share the value of the product transported over the property with the landowner could reduce the barriers to siting and constructing long-distance transmission projects, particularly in low population density, but high renewable energy regions.

e. As more final electricity consumers purchase and operate on-site generation resources (e.g., roof-top solar panels and combined heat and power units) it becomes more difficult to rationalize transmission and distribution service pricing on a dollar per megawatt-hour (MWh) basis. The cost of the transmission and distribution network is primarily a fixed-cost that must be paid by all electricity consumers regardless of the amount of electricity withdrawn from the grid. Consequently, as fewer MWhs are withdrawn from the grid, the dollar per MWh charges for transmission and distribution services must rise. Pricing schemes that recognize the value of the option to withdraw electricity from the transmission and distribution networks when the customer's on-site generation unit is not producing sufficient electricity and the virtually zero marginal cost of withdrawing electricity from the transmission network should replace the current dollar per MWh transmission and distribution charges.

3. *Interval metering and symmetric treatment of load and generation.* Meters that record a customer's consumption at least every hour of the day are necessary to enable electricity consumers to benefit fully from wholesale electricity competition and from managing the intermittent supply of electricity associated with a larger capacity share of renewable generation resources. Moreover, unless these meters are accompanied by default hourly retail prices that pass through the hourly wholesale price signal, few if any, of these benefits will be realized by electricity

consumers. The potential benefits of a “smart grid” will largely go unrealized because there is little financial incentive for any market participant to capture them.

a. The business case for interval meters can be made based on meter reader labor cost savings, better distribution network outage monitoring, and the ability of retailers to implement dynamic pricing programs. However, given the current state of the economy, many state regulators may have little appetite to implement a technology that will put meter readers out of work, even if it means lower average prices paid by retail electricity consumers. Without interval meters it is impossible for a customer to benefit from paying a retail price that passes through the hourly wholesale price.

b. State regulators are also extremely reluctant to implement default dynamic pricing programs in spite of the overwhelming empirical evidence that customers are able to reduce their demand substantially (between 10 to 25 percent) during periods of the day with higher prices. Default dynamic pricing also would reduce system peaks and the accompanying need to operate high-cost and greenhouse gas emissions-intensive sources of electricity.

c. The paradigm of a fixed retail price at which a customer can consume all of the energy he or she desires may have been acceptable during the former vertically-integrated monopoly regime when the customer’s utility served as a kilowatt-hour (KWh) insurance provider. The customer paid a fixed “insurance premium” or price per KWh consumed regardless of the current cost to produce the KWh, and in exchange the utility provided all of the KWhs that the customer wanted at that price. In a world with an increasing share of intermittent resources such as wind and solar energy, this KWh insurance model is too costly for final consumers because of the enormous economic and environmental cost of managing intermittency without active participation of final consumers in the wholesale electricity market.

d. Default dynamic pricing in combination with an increasing share of intermittent resources will make investments in the energy storage technologies necessary to manage this intermittency economic. The value of storage is the ability to buy at a low price when there is a substantial amount of renewable energy, and sell when there is much less renewable energy and the wholesale price is high. In the case of wind, which is the lowest-cost widely available renewable energy source, the peak and trough of the daily electricity production cycle is exactly out of sync with the peak and trough of the daily demand cycle in most parts of the country, which makes energy storage essential to accommodating a larger share of wind energy.

e. Unless final consumers face a default hourly retail price that passes through the hourly wholesale price, they will have no financial incentive to shift their consumption away from hours when renewable resources are not producing sufficient electricity or invest in energy storage technologies that allow them to store electricity during low-priced periods and consume it during high-priced periods. It's important to emphasize that passing through these hourly wholesale price signals in hourly retail prices is likely to allow customers to reduce their annual electricity bill relative to a single fixed retail price because they now have the ability to consume less during periods with high wholesale prices and more during periods with low wholesale prices.

4. *Limited ability and benefits from switching to lower carbon sources of energy.* Running more efficient natural gas-fired generation more intensively and coal-fired generation units less intensively can significantly reduce GHG emissions from the electricity sector. Retrofitting coal-fired generation units to burn natural gas can also significantly reduce GHG emissions from the electricity sector. The lack of a price for GHG emissions significantly limits the financial incentives for this fuel switching to occur and the substantial regulatory barriers to repowering generation units near major load centers further dulls this financial incentive.

    a. More than 50 percent of the electricity consumed in the United States is supplied from coal-fired power plants. Switching these generation units to burn natural gas can reduce the GHG emissions produced per megawatt-hour of energy produced by more than 50 percent. In addition, natural gas is increasingly cost-competitive with coal because of technological change in the production of natural gas from unconventional sources. Most state-level regulatory processes do not currently allow cost recovery for the regulated utility to make this fuel switch. In addition, the lack of a price for GHG emissions from the electricity sector in the United States implies that the generation unit owner realizes little financial benefit from reducing its GHG emissions by switching to natural gas.

    b. There are also many local environmental benefits from switching to natural gas, because SO_2 emission, NO_X emissions, and particulates emissions associated with burning coal are all substantially higher per MWh of electricity produced relative to burning natural gas. In regions with SO_2 emissions and NO_X emissions permit markets, positive prices for these permits creates a financial incentive for the generation unit owner switch to burning natural gas, but it is often extremely difficult to obtain regulatory approval to re-power a coal-fired generation unit to use natural gas.

c. Many of the generation units that currently burn coal or emit significant amounts of GHGs per MWh of energy produced are in transmission-constrained regions. Without additional transmission investments to bring alternative supplies of energy into these regions it can create significant reliability risks to take these units offline to install the equipment necessary to switch the input fossil fuel. This desire to switch many of the older units located near the major load centers to a less GHG emissions-intensive fossil fuel provides another rationale for a regional planning process that promotes network expansions in transmission-constrained areas.

d. In many control areas with substantial amounts of efficient combined cycle gas turbine (CCGT) generation units, the configuration of the transmission network still requires more GHG-emissions-intensive natural gas-fired or coal-fired generation units to operate. Specifically, a hypothetical dispatch of generation units without regard to their location or the location of demand in the transmission network would result in substantially more energy being produced from the less GHG-emissions-intensive generation units. Instead, the actual dispatch must involve more GHG-emissions-intensive units because there is inadequate transmission capacity to deliver all of the potential output of the efficient generation units to final electricity consumers. Because of these GHG-emissions-intensive units local to major load centers must often operate regardless of the price of natural gas versus coal, this reduces the benefits to investments in lower carbon generation technologies.

5. *Barriers to the development of unconventional sources of natural gas and LNG*. Natural gas has the potential to become a transitional fossil fuel to a significantly lower carbon electricity sector. This will require substantial increases in domestic natural gas consumption which will require increases in the supply of natural gas from both unconventional sources and liquefied natural gas (LNG) imports.

a. The recent discoveries of substantial unconventional natural gas (tight sands gas, coalbed methane, shale gas, and methane hydrates) reserves in the United States has resulted in a substantial decline in the domestic price of natural gas from an all-time high less than five years ago. However, there are significant legal and regulatory challenges to developing these unconventional natural gas resources because of their location and how they are extracted. The major concern is potential for contamination of the drinking water during the fracturing process. Most states have yet to develop clear regulatory frameworks to allow the development of these resources with minimal environmental harm.

b. Large natural gas resources exist around the world and are less geographically concentrated than oil reserves. However, the liquefaction and pipeline infrastructure necessary to transport this natural gas to consuming regions is expensive to construct and maintain. Creating a vibrant world market for natural gas similar to the world oil market should have enormous benefits to United States consumers, including a process for the siting, construction, and operation of liquefied natural gas facilities that will foster the development of this world market for natural gas. Although California relies on natural gas for virtually all of its fossil fuel generation needs, currently there are no LNG import facilities on the entire west coast of the continental United States. Even if domestic unconventional natural gas resources prove to be sufficient to meet United States demand, LNG can still compete with domestic natural gas at domestic prices that are expected to prevail over the near term and certainly over the long term.

6. *Barriers to the development of carbon capture and sequestration facilities*. For both political and economic reasons, it is highly unlikely that the United States electricity sector will be able to significantly reduce its consumption of coal in the near term. The deployment of carbon capture and sequestration (CCS) technologies at scale can allow the United States to continue to burn coal in the electricity sector.

    a. The United States has the world's largest coal reserves, and coal is the world's fastest growing fossil fuel in terms of total BTUs consumed over the past decade. This is unlikely to change given the growth in the demand for coal from the developing world, particularly China and India. Understanding how to capture and sequester GHG emissions from commercial scale coal-fired power plants could substantially reduce GHG emissions from the United States and provide a leverage point for reducing GHG emissions from the developing world. Developing a state-level regulatory process for the siting of carbon capture and sequestration facilities is necessary for the long-term development of this technology at scale.