Before the Science, Technology and Telecommunications Committee
Testimony of Wayne Shirley
Transmission Issues for Green Energy
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Introduction

Mr. Chairman and members of the committee, thank you for inviting me to testify today. My name is Wayne Shirley. I am a Principal and Director of The Regulatory Assistance Project, commonly known as RAP. RAP is a non-profit organization all of whose Principals and Senior Associates are former utility commissioners or long-term utility commission staff. Our mission is to provide policy guidance and support to state and federal policymakers, including legislatures, regulators and their staff in the US and in China, India, the EU and Latin America.

We are primarily grant-funded by private foundations and by US DOE and US EPA. We do not represent or hire ourselves out to private interests or advocates. We do, however, sometimes provide testimony before committees such as this and, on rare occasions before regulatory agencies when invited by such committees or agencies to do so. More often, we provide workshops, issue development and facilitation services to regulators and regulatory stakeholders – mostly free of charge to the recipients.

As many of you may recall, from 1995 to 1998 I was Chair of the New Mexico Public Utilities Commission, a predecessor agency to the Public Regulation Commission. Prior to that most of my career was spent as an advocate for ratepayers – first as Director of the Energy Unit of the New Mexico Attorney General's office, under Paul Bardacke and later as the lead attorney representing the New Mexico Industrial Energy Consumers. For the past decade, I have been a director and principal at RAP.

The Changing Nature of the Electric Sector

I have been invited to address issues relating to electric transmission for green energy. I'd like to start with some context for this topic. The electric sector we see today bears little resemblance to its former self, having come from a nationwide industry structure of vertically integrated and vertically regulated in-state utilities to one of fractured institutional and market structures. For many decades the industry operated in as nearly a steady state as one could imagine, with steadily declining per unit costs. For utilities and regulators, life was simple in many respects. You knew your load and costs would grow at predictable rates and increasing economies of scale were driving down prices. If you'll permit me the metaphor, this was *Regulation 1.0*.

To say the least, times have changed and have been changing for some time. A number of shocks to the sector began in the late 1970s and through the mid-1980s. From nuclear safety concerns to excess capacity, suddenly we could and did face higher costs. To make matters worse, load growth was no longer as predictable and overall had begun to slow, compressing the costs over fewer sales units and increasing prices. At the same time, the cost of fuel became more volatile and the overall risk in the sector, for both utilities and consumers, became greater.

During this period, regulation also underwent changes. A major milestone for this was, without doubt, the Public Utilities Regulatory Policies Act of 1978, or PURPA, as it is more commonly called. PURPA had two important impacts on the electric sector. First, it introduced for the first time the notion of customer-owned renewable or high efficiency generation in a sector which had, until then, enjoyed a 100% regulated monopoly status, to the exclusion of new entrants.

Second, it employed an economic standard, that of avoided costs, which proved to be insightful, though difficult to administer. The theory was simple – a utility should be willing to pay a third party for energy or capacity an amount equal to what it saved by avoiding the construction or operation of its own generation. To qualify for this arrangement, the generator essentially had to either be a renewable resource or a high efficiency generator – usually what was then called a co-generator that could capture waste heat from an industrial or commercial process and convert it to electricity.

In application, the avoided cost concept proved to be somewhat difficult to administer because the avoided cost price had to be set as a tariff in a regulatory proceeding and was subject to a variety of economic approaches and significant regulatory litigation, yielding divergent results around the country. PURPA was, if you will, Regulation 1.1.

In the 1990s a succession of energy laws created the concept of exempt wholesale generators who, if they had access to the capital, could build and operate their own generating stations and sell the output into wholesale markets. At the federal level, the Federal Energy Regulatory Commission adopted an open access policy for transmission, theoretically opening up the grid for use by competitive generators. In addition, multi-utility organizations, known as independent system operators (ISOs) and regional transmission organizations (RTOs) evolved in some parts of the country to provide market structure and to reform operations to reflect the these new realities. In effect, this was Regulation 1.2.

Subsequently, perceiving inefficiencies in the traditional vertically integrated utility model, approximately one-half of the states restructured their utilities in an effort to bring greater competition to the electric sector. These efforts have been met with mixed success and some of those states have attempted to rollback reform or re-introduce regulation. This is the current state of affairs in the US – Regulation 1.3.

Today, looking forward, we are on the verge of a major leap to Regulation 2.0, which will need to be structured for and in response to, if you will, Electricity 2.0. From both a utility operations point of view and that of a consumer, the Information Age, has largely bypassed the electric grid. But much of that is likely to change, and perhaps soon, as new technologies become operational and consumer products are brought to market.

Much of this new technology comes under the umbrella of an emerging phenomenon we call "smart grid." There is no fixed or industry-wide definition of what a smart grid really is. But at its core, it's about having more knowledge about individual consumption information, higher resolution operational monitoring of the grid, greater control of the grid, greater control over end-use loads and a host of other very "gee whiz" ideas that range from smart appliances to remote control of your energy consuming appliances from your cell phone or the internet. The smart grid will be heavily dependent on computing and communications throughout the grid.

There are a number of companies with operations in New Mexico that seek to provide smart grid goods or services. In addition, Smart Grid demonstration projects are proposed for New Mexico to demonstrate these new capabilities.

At the generation level, utility-scale renewable resources, such as wind, biomass and even solar, are now common place. Emerging storage technologies, including concentrating solar power (CSP), which can store heat for later electric generation, may further transform the industry. Utility-scale batteries are even on the horizon.

In terms of consumer loads on the system, another great pressure which is likely to emerge in the electric sector is the integration of substantial new evening-time demand from plug-in electric hybrid vehicles. Just this week, two of California's largest utilities announced that they will be rolling out infrastructure changes to support plug-in hybrids.

System impacts from plug-in vehicles include deployment of charging stations, as well as considerable changes to the configuration of the system grid. In some visions of the electric hybrid future, our cars will actually become large scale collective storage batteries which can be dispatched, presumably for a fee paid to the car's owner, by electric system operators to meet system needs, whether for reliability or economic reasons. Plug-in electric hybrid vehicles are not really here yet, but most agree this change is on the way.

Meanwhile, customer-owned small scale generation – especially rooftop photo-voltaics – are now available in standardized packages, ready to interconnect to the grid. Other small scale energy and energy management systems are in the offing. Even Google has entered the energy management business with its PowerMeter© product. These large scale changes to the electric sector, Regulation 2.0, are just around the corner. If Regulation 1.0 was the embodiment of stability, Regulation 2.0 promises to be just the opposite: a world where virtually every input is variable and carries significant uncertainty and volatility.

With all this in play, we are also coming to grips with a new constraint – limits on CO_2 emissions – and so we have significant pressure to clean up our electric emissions, even in the face of continuing load growth. Prudent industry planners are preparing for valuing CO_2. While the details are still to be written, some value for carbon should be part of decision-making today.

In all, it seems a daunting prospect and in some respects I suppose it is, but there are many leverage points where legislatures and regulators can take action to minimize the costs, and perhaps actually produce net savings to consumers.

Despite all these changes, that fundamental notion of avoided costs that PURPA brought us underlies much of modern regulation and political discourse, in both theory and practice, in the form of integrated resource planning or IRP. But, IRP asks a more sophisticated question: *Looking out over time, what is the combination of resource choices which meets our needs at the lowest cost?* Or, put another way, is it cheaper to build this generator or that transmission line or some other facility than the other options available to us, such as energy efficiency or distributed generation, that could defer or avoid it? Even more simply, when asking "Does it cost too much?" one must first ask, "As compared to what?" in order to provide an answer. The foundation of IRP is that it explores all viable alternatives, including so-called demand-side resources in its pursuit of the answer to the "As compared to what?" question. I recommend this framework to you when assessing how public policy should adapt to the changes we are facing. This approach improves understanding of when it is beneficial to bear some short-run expense in return for long-term benefits.

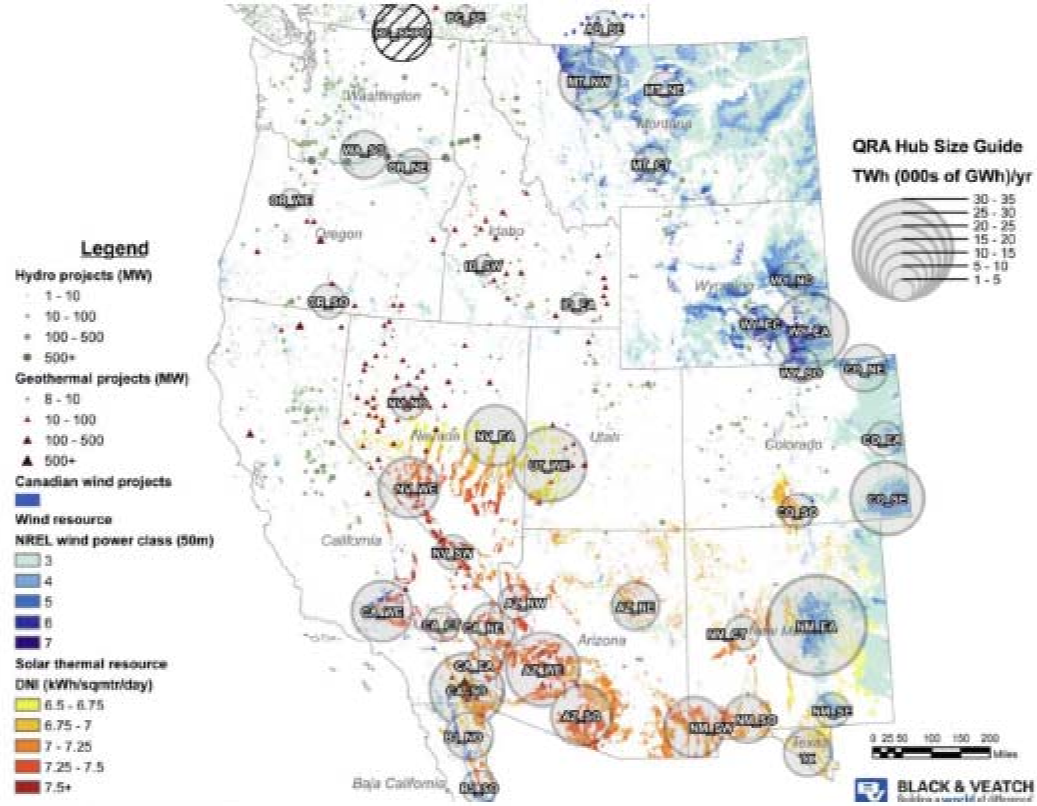
Today, there are a number of reasons to encourage green energy, ranging from the jobs potential associated with developing a new green industry, to the more pragmatic goal of meeting expected limits on carbon emissions from federal carbon caps. In New Mexico, we already have both an energy efficiency resource standard and a renewable portfolio standard. Regardless of the purpose, however, public policy should aim to accomplish its goals at the least cost to consumers and society. For purposes of my comments here today, this is an overarching principle.

Is Transmission Needed for Green Energy?[1]

As part of its objective of deploying 30,000 MW of renewable energy by 2015 and to assess the relationship between renewable resources and transmission needs, the Western Governors Association (WGA), working with the Western Electricity Coordinating Council (WECC) sponsored the Western Renewable Energy Zone (WREZ) effort to identify major renewable resource zones throughout the West. Figure 1, reflects the zones identified in that process:

[1] My comments will focus primarily on issues related to transmission and renewable energy within the western electricity interconnection, which serves utilities from the Rocky Mountains to the Pacific coast and from northern Mexico to Canada. I would have corollary comments, likely somewhat modified, in the context of these issues in the eastern interconnection to which much of eastern NM is connected. The institutional details are different, but the fundamentals are the same.

Figure 1: Western Renewable Energy Zones

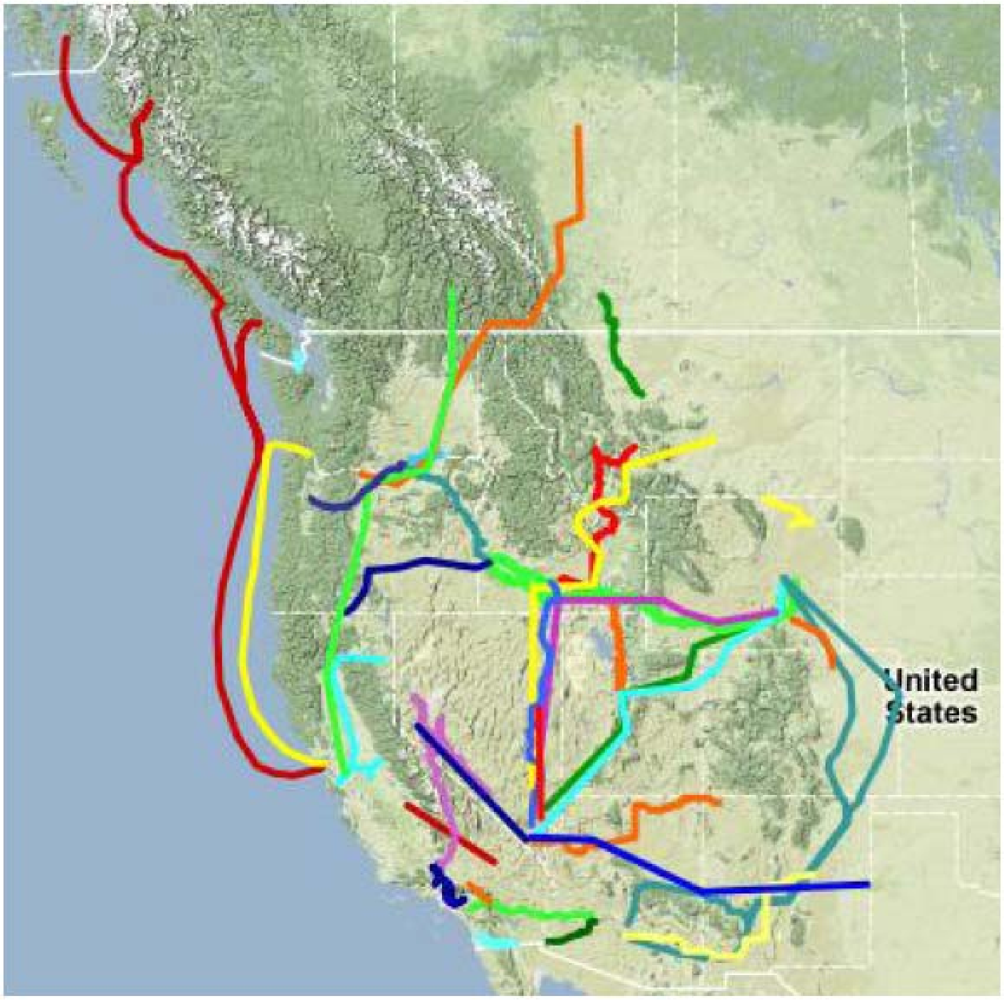


Source: Presentation by John Savage, Oregon Public Utility Commissioner/Chair, WREZ

As you can see on this map, considerable wind and solar resources are identified within New Mexico.

Given these zones, do we need transmission to support renewable energy? Virtually everyone familiar with our transmission system agrees that new transmission lines must be built over the coming years. Indeed, a large number of transmission projects have been proposed in the West as reflected in Figure 2:

Figure 2: Examples of Proposed New Transmission Lines in the West



Source: Presentation by John Savage, Oregon Public Utility Commissioner/Chair, WREZ

Some are proposed by one or more utilities and others wholly or significantly by merchant ventures with little or no utility involvement. Many purport to be transmission being built explicitly for renewable resources. Others are offered as part of a new hyper-scale backbone system designed to move very large amounts of power from renewable rich areas to renewable poor load centers.

As can be seen, some of these would be sited within New Mexico. In fact, the proposed lines in New Mexico, not all of which are reflected in Figure 2, present three different types of projects. One project, the so-called High Plains Express would install a large capacity, backbone type transmission line running the along the eastern front of the Rockies from Wyoming to New Mexico to Arizona. Its primary purpose is to provide an avenue for moving energy from Wyoming to Arizona, whether and how New Mexico located renewables would utilize this line is somewhat unclear.

Another proposed line, the Sun-Zia project, proposes to connect a wind rich area in Southeastern New Mexico to loads centers in Arizona (and potentially beyond). Lines such as this offer the opportunity for creating a renewable energy export market for New Mexico-based renewables.

Finally, there are proposed lines which are principally or solely within New Mexico and are designed to connect New Mexico resources to New Mexico load centers. These lines would presumably support achievement of the renewable portfolio standards applicable to New Mexico utilities.

State Role in Transmission Planning

None of these proposed lines can be built and connected to the grid without considerable planning and analysis. Any time a significant operational asset such as a large generator or a transmission line is added to the system, it can potentially adversely affect the reliability and operation of the grid. All such facilities, must therefore, undergo a planning and operational impact review.

From an institutional point of view, both the process for planning and our existing operational configuration leave much to be desired. We lack a rational institutional framework to fill the gap between state concerns and federal concerns – that is, the regional and sub-regional zones within the Western Interconnection.

Prior to the 1960s, utility systems were largely owned and operated by individual utilities, each of which, with few exceptions, operated exclusively or predominantly within one state. During this period, utilities were largely vertically integrated and vertically regulated. In this context, each utility planned for its own needs. If it built a new generator, it would build a transmission line to connect to it. In some cases, a utility might co-own a generating station with another utility and would share the cost of that generator and share some or all of the cost of transmission to connect that generator to each of the owner's load centers. Planning considerations were limited primarily to the supply-side needs of the utility. During this period, transmission facilities designed to interconnect utilities on a regional basis were limited and such interconnections would likely be considered weak by today's standards. Regulators typically reviewed utility plans sporadically or when new construction projects were proposed by their local utilities. Little, if any, consideration of system impacts or regional concerns was embodied in these reviews.

Meanwhile and for a variety of reasons, since the 1960s utilities have become increasingly interconnected with transmission lines and more dependent on one another's systems and how they are operated and expanded. In most cases, the "need" for these lines has been defined primarily either by the direct need for more generation or, with increasing frequency, the need to address reliability and operational issues of an ever-more complex system or to create opportunities for wholesale transactions between utilities to take advantage of cost differentials between utility systems. Virtually none of the system was designed or deployed for the explicit purpose of integrating more renewable resources.

Today, we face a much different challenge. While transmission planning historically focused on generating needs and reliability issues, today transmission planning must embrace a new purpose – that of reducing the carbon emissions of our power supply. From an economic standpoint, traditional planning was, or should have been, based on a least-cost standard. That is, "*What is the lowest cost way to meet the energy needs of customers?"* In the 1980s, least-cost planning lead to the more comprehensive planning concept called integrated resource planning (IRP), which expanded the question to include a comparison to all viable options, including the costs and benefits of avoiding energy consumption through load management and efficiency.

Carbon constraints impose a new dimension in planning. While past planning tended to focus almost exclusive on reliability and least cost, expected limitations on carbon emissions will operate as an external constraint on the options available. Whether you support CO_2 regulation or not, the reality is that it appears Congress will be imposing a cap on CO_2 emissions in the near future and that the cap will be steadily reduced over time. Planning in the electric sector, whether it be for generation or transmission, should, indeed must, now be conducted on the basis that it is constrained by limitations on CO_2 emissions.

Having a planning *constraint* is much different than the traditional cost-benefit analysis. That is, the question is not whether the benefits of carbon reductions are worth the costs, because framing the question in this way suggests that failing to reduce carbon is an option. Once carbon has been capped as a matter of law, options to avoid carbon reductions will be limited and over time will not be available at all – in short, the law will require reductions in carbon emissions and the utility system must be planned accordingly.

Thus, the question becomes, "*What is the least cost path for meeting our energy needs, recognizing the carbon constraints we face?"*

Challenges in a Constrained Planning Environment

Utility system planning and operations are designed to fulfill the basic objective of assuring that the energy needs of the public are met without unreasonable interruption and at the lowest reasonable cost. We commonly think of this as assuring adequate supplies for meeting consumer demand, but what is most often overlooked, especially by the casual observer, is the ability to reduce the level of demand in the first place as a means to meeting this objective. As it turns out, reducing demand through load management and energy efficiency is the cheapest way to balance supply and demand. In fact, it is useful to think of supply and demand as equivalent resources. As a rule of thumb, energy efficiency costs on the order of $0.03/kWh – less than half of the all-in costs for any supply-side alternative and perhaps just one-quarter or less than a new coal or nuclear plant. Therefore, from a policy perspective, it is crucial to maximize the deployment of energy efficiency to help offset more costly solutions to reducing carbon emissions.

But efficiency and distributed resources alone cannot sustain our needs in the long-term – new resources must be deployed and, more importantly, embedded carbon emitting resources must either be retired or their carbon emissions must be abated and the lost generating capacity must be replaced with new clean resources. We simply cannot meet the levels of carbon reductions contemplated by current legislation, which call for reductions in our carbon emissions to levels on the order of 80% below 2000 emission levels by 2050, without also eliminating current emission sources. So, while renewable portfolio standards and energy efficiency resources standards are important tools that have already been adopted in New Mexico, they are not sufficient to solve the problem. To accomplish this, our regulatory framework and its role in the regional and West-wide planning process must be reformed and all unnecessary regulatory and market barriers to clean resources must be removed. Public policy must favor clean resources.

All of this leads to a more complex and interactive process for transmission planning. Whether and how much new transmission we need will be driven by two countervailing forces. On the one hand, we will definitely need new lines to connect renewable rich areas to the grid. On the other hand, existing transmission currently serving carbon-based resources can be used to transport more clean energy as the carbon-based resources are retired or their carbon emissions (and therefore their effective output) are abated.

The Role of Regulation in Transmission Planning

When it comes to actual transmission planning, utilities and transmission developers typically do their own planning for system needs that are essentially local to their own utility systems or to meet their particular market needs. Virtually all transmission projects, however, will impact neighboring systems or are, by design, regional or even system-wide in nature. Regulators play an important role in assuring that the planning process considers appropriate alternatives for proposed projects and that they are both needed and are the most economic solution to transmission needs.

Table 1 reflects just some of the existing organizations involved in transmission planning in the West:

Table 1: Organizations Involved in Transmission Planning in the West

Western Governors Association • Western Interstate Energy Board (WIEB)   o Committee on Regional Electric Power Cooperation (CREPC)

Western Electricity Coordinating Council (WECC)
• Transmission Expansion Policy Planning Committee (TEPPC)
    o Planning Coordination Committee
    o Studies Workgroup

Ad Hoc Sub-regional Planning Groups • Columbia Grid • Northern Tier Transmission Group (NTTG) • California Independent System Operator (CAISO) • Sierra • Colorado Coordinated Planning Group (CCPG) • Southwest Area Transmission (SWAT) – includes most of New Mexico & Arizona

The Western Governors Association, through the Western Interstate Energy Board has hosted the Committee on Regional Electric Power Cooperation (CREPC) for many years. This forum has been an important resource for both state agencies and utilities to educate regulators about issues facing the industry and to educate utilities about regulatory concerns.

WECC is the west-wide reliability council. Its primary mission is to assure and maintain the high reliability of our electric grid. Virtually no new generation or transmission can be implemented without a WECC review for system impacts. That said, WECC has no planning authority, does not propose projects or design them and does not require utilities to have any particular planning activity. It has, however, attempted to provide a coordinating role for planning and is actively engaged in rolling out a region-wide framework for planning.

These planning forums all have one common characteristic – none of them have any legal authority to conduct planning or to require any utility or merchant company to comply with a planning regime or any particular plan. That said, as a group, some very good planning work is being accomplished by these organizations. One reason for this is the sheer necessity of coordinating planning efforts in a way that assures that the lights stay on. Another compelling reason is to resist and avoid the potential for intervention, perhaps even pre-emption, by the Federal Energy Regulatory Commission which has made clear that planning for transmission must evolve past the traditional utility-centric process to a more public process with robust public participation and with greater consideration of non-traditional solutions to transmission issues.

How these groups will coordinate and interface is still being determined. WECC has recently made a proposal for funding from DOE to formalize the planning process, and to improve and expand public participation in the process. In a parallel and somewhat coordinated request, WIEB and CREPC are seeking additional funding to support state agency participation in the process and to provide an avenue for states to assure their interests are addressed in the planning process.

State participation in these forums occurs primarily through two types of agencies – state energy offices and state regulatory agencies. Historically, New Mexico has been actively involved in CREPC. It has also participated, at least in a monitoring mode, in SWAT. Because much of the structure of the planning process is now being worked out and implemented, continued and vigorous participation by state agencies should be viewed as a high priority need.

Is there such a thing as a green transmission line?

A number of transmission projects have been proposed and marketed as renewable transmission lines. In New Mexico, as in some other states, new transmission authorities have been implemented with a mission of supporting renewable transmission. But labeling a transmission line as green, does not necessarily make it so. Under the existing FERC Open Access Policy, once a transmission line is built, any unreserved capacity on that line must be made available to any generator willing to pay for it. Unless a proposed renewable transmission line is fully subscribed to renewable generators, carbon-emitting resources may very well end up utilizing that line.

Moreover, electricity flows through the paths of least resistance. In an interconnected system, one cannot determine the "color" of the electrons – green or brown – flowing on a given transmission line. Therefore, the "test" of whether a line is "green" or not, is determined by the financial commitments underlying its use. That is, if renewable resources pay for the capacity on the line, it would generally be viewed as meeting a green objective. This is an underlying principle for New Mexico's Renewable Energy Transmission Authority, which requires that affected transmission lines be at least 30% renewable energy.

It is likely that FERC and the states will have to develop a new policy framework for transmission access that either expressly allows for new transmission lines to be reserved for renewable energy, or provides for a new way to allocate capacity toward renewable energy and away from carbon-based generation. Because transmission access is primarily a matter subject to federal regulation, states will need to be vigilant in making their case to the FERC on how these policy changes are implemented. A number of so-called "clean first" approaches are already being proposed in regulatory circles to address this issue.

Challenges for Regulators

Regulators will also be faced with increasing pressure to allow greater access and deployment of renewable resources, independent of whether the regulated utility is a participant. Among the issues that regulators are likely to face are:

- Defining a new regulatory regime;
- Ways to integrate greater renewable resources into the grid;
- Making best use of limited resources to deploy greater renewables;
- Maximizing end-use and operational efficiencies to mitigate the potential for increased costs;
- Understanding how smart grid and other changing technologies will impact the future of the electric sector;

- Developing greater coordination and cooperation with neighboring state regulators;
- Interstate transmission cost allocation; and,
- Transforming the utility business model.

Defining a New Regulatory Regime

From a state perspective, perhaps the biggest challenge we face is re-formulating our notions of utility regulation to be consistent with new public policy objectives. The utility sector is large and, as a society, we have significant capital invested in it. Given our regulatory history, most, if not all, of the embedded investment in the system will be recovered through traditional regulatory means over some significant period of time going forward. In effect, there is a large financial inertia in our existing system which we cannot avoid.

Without clear guidance or compelling reasons to do so, regulation may continue to be implemented through the lens of traditional regulation – but regulators will be increasingly asked to consider non-traditional options for solving our energy needs. Empowering regulators to respond to these changes and to reform regulation to meet them is essential. Both regulators and consumer advocates must come to grips with a new regulatory reality which is constrained by carbon limits. No longer will cost alone be the basis for avoiding clean resources. Instead, reduction of carbon through renewable energy and efficiency goals will become part of the core objectives of regulation – with carbon limits operating as constraints on the choices available to achieve our traditional goals of reliability and reasonable cost.

Integration of More Renewable Resources

A major obstacle to greater use of renewable energy is the intermittent nature of many renewable resources, especially wind and solar photo-voltaics. These resources produce energy when the wind blows or sun shines, but not otherwise. At small levels of deployment, the sudden loss of generation when wind stops blowing or a cloud passes over can be overcome with load following generators. As the share of total generation grows, this becomes much more problematic. But some simple changes to the way the system is operated can help overcome this and expand the maximum amount of intermittent resources that can be utilized.

Currently, we have dozens of so-called “control areas” in the Western Interconnection, which are responsible for operating discrete portions of the system – typically a single utility’s operations or some sub-part of those operations. They are each required to operate within certain engineering parameters, including having necessary standby generating resources to offset the loss of intermittent renewables. This means each one must absorb the variability from renewable resources individually. If, on the other hand, theses control areas were consolidated into just a few zones, operators could take advantage of the geographic diversity of renewables which are installed across the entire region. While any one wind farm may lack wind at any given time, as group, there is a much lower statistical chance that the wind will stop in all of the locations at the same time. By broadening the control area footprints, operators can minimize the amount of backup power that must be ready to absorb variability in renewable generation – in effect sharing the risk of variability across broad areas. This dramatically lowers the cost of renewable energy. Regulators will be faced with the implications of these changes, including changes in who is responsible for operation of the grid.

Best Use of Limited Resources to Deploy Renewable Energy

Not all renewable energy is equal. In some cases energy production is highly coordinated with system peak loads and therefore has real capacity value for the system. In other cases, energy production may be significant, but not necessarily synchronized with peak loads. In this situation, the resource has significant energy value (and therefore carbon reduction value), but may or may not "count" as capacity to meet peak loads.

Renewables have different collateral costs as well. Some renewables, notably customer-owned rooftop installations require no transmission lines at all and little or no real estate. Other renewables, typically utility scale wind and solar farms, require significant transmission facilities and large tracts of land. A major challenge for regulators is to provide the correct cost and benefit criteria so that the competitive markets in renewable energy can respond accordingly. If we had unlimited resources, we could simply roll out as much of all of these resources as possible. But, of course, we do not have unlimited resources and regulation should serve to assure our resources are well spent.

Some resources are currently favored by federal and state tax credits, yet barriers remain to deployment of many of these resources through artificial caps on the maximum amount of installed capacity allowed on the system or because of competing business objectives of the utilities. There is a potential for conflict here because many utilities want to be providers, perhaps exclusively, of renewable resources, while others seem more content to allow third parties to supply these resources. Limits on the ability of customers to deploy customer-sited resources pose the risk of losing the financial opportunity afforded by current tax credits and supportive rate designs such as net metering or feed-in tariffs, while risking increased future costs to comply with carbon commitments.

Regulators will need to balance the need for diversity among these new resources with achieving the greatest bang for the buck.

Expanding End-use and Operational Efficiencies

One of the best, and easiest, ways to mitigate the potential cost of new resources is through increased efficiency. Our existing electric sector is an enormously inefficient machine. More than half of the energy value we consume from fossil fuels (coal and single cycle natural gas generation), is lost as waste heat. Additional losses are incurred transmitting and transforming electricity. By the time electricity reaches the customer's meter, 70%-80% of the energy value of its fuel has been lost.

Of that 20-30% that passes through the meter, another considerable amount, perhaps another 5-10%, is lost through end-use inefficiency – usually by older, inefficient, appliances or poor consumption habits. Any avoidable inefficiency is best characterized as simple waste – literally burning our money.

New Mexico does have a positive energy efficiency policy, including an energy efficiency resource standard, which calls for minimum efficiency gains. Even so, efficiency continues to endure market failures which erect barriers to the deployment of efficiency. From a regulatory standpoint, energy efficiency is not yet fully recognized as a resource comparable to supply-side resources – even though it is cheaper, more reliable and cleaner than any other resource available. At some point, policy and regulation will need to fully deploy all cost-effective efficiency. Efficiency not only makes economic sense, it is key to mitigating the increased costs we will face meeting carbon obligations.

How Smart Grid and Other New Technologies Will Impact the Electric Sector

As mentioned earlier, increased control and communications in the electric sector is in our future. Currently, open protocols for controlling equipment and status communications are being developed. These new technologies can perform lots of interesting and useful functions. But, it is not clear whether we really need all of these functions, nor whether it is cost effective to deploy them. For example, a sophisticated technology platform can allow system operators to cycle refrigerators and air conditioners on and off during times of system stress, enabling greater reliability of the overall grid. On the other hand, many utilities have simple, low-cost legacy systems for direct load control – rather “dumb” devices, if you will – than can capture much of the same benefit as the new newer and more robust technologies.

Many utilities have or are about to undergo large scale, system-wide, deployments of smart grid technologies. At system-wide scales, the investment requirement is large. On the one hand, this represents a new business model and investment opportunity for utilities. On the other hand, it places significant pressure on overall costs and rates.

To the extent these technologies are deployed, they tend to reduce the total resources needed on the system and can, therefore, change the need for additional resources going forward. This will inevitably impact questions relating to the need for renewable energy and related transmission – especially if the effect is to allow greater integration of distributed, renewable resources which are installed at the customer’s site.

Developing Greater Regional Coordination and Cooperation

One of the toughest challenges facing legislators and regulators is balancing the natural desire to focus on local needs, costs and benefits in an environment where one’s overall well-being is defined by regional decision-making. The electric sector is interconnected across state lines – and not just physically speaking. We are interconnected economically and politically, whether we like it or not. This is especially true when it comes to transmission facilities which may cross a state, without placing any cost burden or delivering any system benefit to that state, other than rights-of-way and some property tax revenue. Siting requirements alone may obstruct the construction of needed facilities, unless states find a way to restrain themselves from the NIMBY urge.

Regulators will, no doubt, be faced with approval requests to construct such facilities in cases where there is great public need – *but not in their own state*. The states must provide the policy framework for attending to this issue, seeking to find a balance between our self-interest and the collective interests of our neighbors.

Interstate Transmission Cost Allocation

The other major interstate concern will be that of cost allocation. It is tempting to think of transmission lines as discrete facilities providing point to point service. In fact, because of the physics of electricity, virtually all transmission lines, in way or another, provide service to all of us – even transmission lines that are one, or several, states away.

To assure that needed transmission lines get built, mechanisms must be developed for sharing their costs among the consumers of different states – some of whom may not even regulate the transmission line owner. This is an on-going topic of concern in the regional organizations that work on transmission planning, but the way forward on this issue is far from clear. It is incumbent on legislators and regulators to be actively involved in these discussions and to develop reasonable solutions to this issue.

Transforming the Utility Business Model

Finally, I want to touch on a collateral, but very important issue – that of the utility business model. It is important to note that, no matter your regulatory approach, all regulation serves to provide an incentive scheme to utilities. Whether those incentives are consistent with or run counter to public policy objectives, is a different matter completely.

Back in the good old days – under Regulation 1.0 – life was easy. Costs were going down and economies of scale were further lowering prices. More consumption was generally perceived as good because of this. But this was a time unconstrained by the challenges we face today.

Fundamental to the business model of the utility was the notion that increased sales, and the revenues that came with it, were part of the profit formula. In effect, we created an incentive mechanism for utilities to encourage greater consumption – even if that consumption was wasteful. This phenomenon is often referred to as the "throughput incentive." It operates as an incentive to increase sales and as a disincentive to reduce sales. Because our regulatory system seeks to assure recovery of all costs incurred to provide service to the public, greater sales had the effect of lowering unit prices. Reduced sales, on the other hand, were actually discouraged because it would have the effect of increasing prices. This mindset remains today among regulators and consumer advocates alike, but it is not a sustainable regulatory model.

One of the emerging trends in the US is the reformation of the utility business model – away from a sales-based model, to a performance or objectives model. Rather than rewarding a utility for increased sales, these new business models seek to reward greater efficiency or cleaner power, while eliminating the throughput incentive. In fact, as I understand it, New Mexico has twice passed legislation directing the Public Regulation Commission to remove disincentives to efficiency – a legislative reference to the throughput issue, yet no resolution of this issue has yet been fully achieved, though the issue is still pending before the PRC. Some form of lost revenue recovery or a pricing technique known as decoupling can correct some or all of this problem, but it does not create a positive profit model for efficiency or renewables and as long as we have for-profit utilities, it is unlikely they will engage in substantial efforts which both reduce profits and offer little or no opportunity to replace those profits.

Regulators, and possibly legislators, will need to be involved in exploring alternatives to traditional regulation. In short, we need an approach where utilities succeed by fulfilling our public policy objectives for cleaner resources and greater efficiency, rather than by undermining them.

Mr. Chairman, that concludes my remarks. I once again want to thank you for the opportunity to be here today and I will be happy to answer any questions.