Transmission Business Line
Programs in Review
Transmission Program Level Costs 2004-2006
The Value of Transmission

Combined Overview

Idaho Falls (July 17, 2002) -- Introduction by Kevin Ward,
Spokane (July 18) -- Introduction by Sally Long,
Portland (July 19) -- Introduction by Kevin Ward
Kennewick (July 24) -- Introduction by Brian Altman
Tacoma (July 25) -- Introduction by Bob Lahmann

> -- page numbers refer to pages in Power Point presentations -- also on the web
> -- also see **Customer Questions and Comments**

History of TBL Programs and Costs: FY 1992 to Present: "Where we have been"
Alan Courts, Vice President, Engineering and Technical Services

From the 1990s up through today the electric industry is changing (*p. 5*)

- Title 7 of the Energy Policy Act of 1992 -- Congress had successfully deregulated the gas and airline industries. This opened transmission access to facilitate competitive wholesale power markets.
- FERC Orders 888 & 889 in 1995-96 -- exposed all our loads to competition all at once. To remain competitive we lowered costs, downsized our workforce and stopped investing in transmission lines.
- August 10, 1996 -- catastrophic outage that affected the entire western US reinforced the concept that the laws of physics hadn't changed and we still need to care for our system. That caused us to refocus on the importance of reliability.
- 2000-01 -- California experiment in regulation, along with drought in both California and the Northwest caused the West Coast electricity crisis. The bottlenecks in the transmission system, ultimately, contributed to the crisis.
- Today's issues: Enron, federal energy bill, RTO West.
- FERC continues its rulemaking: transmission integration and standard market design.

Internally (*p. 6*)

- The nature of the work is changing. With market pressures to keep lines in service, it is increasingly difficult to take outages for maintenance and construction.
    - In the past, whenever we needed to maintain or construct a line, we would just take the line out. Our outage planning has changed.
- The system needs new additions to address bottlenecks, load growth, and new generation seeking transmission service.
- The system is older and under greater stress. Failures result in greater ripple effects.

- Aging workforce. We missed a generation in our workforce as younger people turned to high tech jobs and now we're losing our experienced people. We will need to recover from that.

What we did (*p. 7*)

- 1992-98 -- Intense cost and staffing cuts. We ramped back on capital program 66% and our staffing level dropped by 36%.
- 1996 -- separated TBL and PBL to conform to FERC orders 888 and 889.
- 2002-03 -- We had wrung all the capacity out of the system. In the last rate case, we asked for a little more revenue to recover from the cost-cutting (we had gone too far) and to address constraints, growing loads and a stressed system.

Constant direction (*p. 8*)

- We recognized in the last rate case that there was not enough capacity margin in the system and that we couldn't squeeze more out. We haven't changed that direction. Our theme is not new, we are just intensifying our work.
- 2002-03 -- beginning infrastructure projects and reliability centered maintenance

Capital Program
Vicki VanZandt, Vice President, Operations and Planning

"For a lot of our transmission services, we're sold out!"

We've been anxious about our transmission system and the state of our infrastructure since the last time we were out to talk with you (1999). Today you will see increases in our capital investment planning. There are two drivers (*p. 10*): We need to keep up with a reasonable replacement plan and our infrastructure program needs to include replacements. In addition, we need new infrastructure.

- Replacements -- our existing 15,000 circuit miles of transmission lines won't work the way we need them to and they now need some care and feeding. That includes replacing aging facilities "just in time."
- Infrastructure program -- We've seen different generating patterns since 1996, but that has really accelerated since the California market opened. Also, last year was the second driest on record and we had less supply from the Columbia River. We saw price spikes and unusual transmission use. For example, power was sent up the DC intertie from southern California and down the AC interties to northern California to get around California's congested Path 15.
- We need to remove constraints that limit economic trade to let the market work. The proposal won't fix all congestion, but it addresses most. We need both a supply and transportation system that provides the power when the market needs it to prevent price spikes. And we need more capacity to keep the system stable so it does not cascade out of service.

TBL Capital Projects -- Trends (graph *p. 11*)

- 1992-93 -- We were finishing up the third AC Intertie in these years.

- After that dropped investments and cut costs. We had some margin in the system and used special relays, remedial action schemes, shunt capacitors and communications to get the most out of the system. I'm surprised at how fast that margin has disappeared and am less than comfortable with the system now.

We haven't built anything of significant proportion since 1997 (the exception to this is the Swan Valley-Teton line), but loads have been growing at an average of 1.8% per year (*p. 12*). In addition to needing to provide more capacity, customers also want predictability. They want a monthly product they can rely on. (The regulatory environment may have affected the lack of construction, too. The question arises: can you recover costs when building a project?)

But, there is a limit beyond what we can get through these methods. The crisis is not just about supply, it's also about bottlenecks. We need a little surplus in both supply and in transmission.

August 10, 1996, we had a loss of load (*p. 13*). That resulted in a change in reliability criteria, including boosts in the reactive (VAR) margin and transfer levels. As a result of all of these reviews, capacity all over the West went down. There continues to be ongoing reviews.

Before deregulation, loads were consistent with long term contracts. However, we've had some unusual generation and transmission patterns lately. During the recent California crisis, there was enough supply in southern California for northern California, but Path 15 between Bakersfield and the Bay area prevented the energy from getting through. Suppliers sent the power up the DC line to the Columbia River and back down the AC interties to northern California. While that was pretty good financially, it was difficult to regulate. These really odd generation patterns are putting a big stress on our transmission system.

Transmission Line Construction -- Operating Circuit Miles -- graph (*p. 14*)
The graph shows a build-up of 115 kV and 230 kV lines through the 1960s and then construction of those lines flatten out and we begin the buildup of 500 kV lines in the late 1960s. We had a buildup through 1987 and then construction has been pretty flat since then.

Infrastructure: Transmission Needs -- Graph (*p. 15*)
According to NW Power Pool information, the highest peak on the system was in 1998 and we expect a 12% increase over that by 2008. Yet, without the infrastructure projects, we would have only increased transmission circuit miles by 2% and most of that is small transmission.

Northwest Constrained Paths -- Map (*p. 16*)
You've seen this map before, but now there are more red lines (constrained paths).

- Those with vertical lines are generally clogged up in the winter and fall when eastern generation is trying to get to western population centers. The distance is short -- about 300 miles. They are resistance load and easier to manage.
- Those with horizontal lines are generally constrained in the spring and summer as our hydro generation goes south to California. The distances are greater -- about 1,000 miles. The temperatures are higher. They are inductive loads and much more difficult to manage. There were line limits North of Hanford this week and North of John Day was sold out. We curtailed at the Oregon/California border. Significant bottlenecks effect commercial activities and some reliability.
- We are continuing to post new constrained paths. We just posted West of McNary on OASIS.
- We used to rely on imports from Canada and from California, but we can't count on those anymore. So, supplies from the east are becoming more important. However, West of Hatwaii and other paths are constrained most of the time. It's not just seasonal.

Illustration (*p. 17*)

- This is how a 300 MW outage behaved on a path between Alberta and British Columbia in August 2000. Lightning tripped the line and was brought back into service quickly. Any time there is a shock on the system, we expect small wiggles (oscillations). What really happened was that the oscillations lasted much longer and was felt further away than we had modeled. The second illustration shows actual as measured at the Oregon/California border. We thought the transmission system was better dampened than this.
- Small changes create big changes in the system, showing signs that the system is under significant stress and needs reinforcements. We need to improve the damping levels and to do this we need new wires.
- As a result of this event, the models were modified. That resulted in removing capacity from the system and increasing congestion even more.
- Also, in an October 14 event at Coalstrip, a little change in power created a big change in voltage. Our power system is telling us we need to ease off a little.

Proposed projects include 700 miles of new transmission line, three new substations, some capacitors and the Celilo upgrade (*p. 18*).

- Reinforce load centers
- Accommodate new generation. 34,000 MW in our queue of generators who have asked for transmission or a feasibility study. Not all will get built, but some are now under construction. Others will be built, totaling 8,000 MW to 12,000 MW depending on where the generation is built.
- Congestion -- See the correlation between the constrained paths, the infrastructure proposals and the generation proposals. Congestion across the North of John Day cutplane creates a backlog hundreds of megawatts deep. If Path 15 in California would have been fixed, prices would have moderated. However, these projects do not relieve all congestion.

- Reliability -- I don't want to be around if the system falls apart like it did August 10, 1996. That started with a line going out due to it sagging into a filbert tree near Albany, Oregon and the system cascaded until the Western system was out.

Infrastructure Projects G-20 -- Map (*p. 19*)
Of the 20 infrastructure projects, some are further along than others.
- Kangley-Echo Lake is one of the most important. It reinforces Seattle, allows us to meet treaty obligations, which go up by 400 MW in April 2003. Since no one has seen construction for a long time, it is facing significant siting issues.
- Coulee-Bell -- reinforces West of Hatwaii and addresses congestion problems.
- Schultz-Wautoma 500 kV -- reinforces congestion at North of John Day and West of Hatwaii, also addresses an agreement with the National Marine Fisheries Service to take some pressure off the river.
- John Day-McNary 500 kV line -- Generation interconnection.
- I-5 corridor -- There is only one 500 kV line between Portland and Seattle. This addresses the stability margin and generation interconnections.
- Olympic reinforcement -- This is strictly for load service and may lend itself to a transmission alternative.
- Monroe-Echo Lake -- also may lend itself to a transmission alternative.
- Dashed lines are place holders for projects into Montana and into Idaho. These are necessary, but not far along in planning. There are a string of constraints from Coulee into Montana. We're not sure about the final plan for these yet. We will do something, but it may be different than what we think now. For example, a planned 230 kV line from Brownlee to McNary could end up being a 500 kV line and the termination point could change.

Area & Customer Service (*p. 20*): So that's the main grid, but not all of what we plan is about the G-20 projects. Also some load service for customers. The Swan Valley-Teton line is an example. There is a fair amount of capital dollars assigned to these. They are customer-driven and customer planned. OPALCO cable, the Palisades to Goshen and Palisades to Snake River 161 kV lines, the southern Oregon reinforcement project and the Albany to Eugene line are examples. Often, we don't hear about the project until later in the planning stages.

Capital Upgrades & Additions (*p. 21*) Also see Appendix (*p. 2*)
We can't rely on controls and communications alone, but will continue to use Remedial Action Schemes (RAS)
- Through West of Hatwaii cutplane, 700 MW of load went away and we all of a sudden needed to deliver more generation through constrained paths.
- Other upgrades and additions due to control schemes
- We've completed our fiber build-out and are now working on terminal equipment.
- Computer systems, such as billing, E-Tagging, SCADA, IT computer systems and keeping up with the OASIS requirements.

System Replacements (*p. 22-30*)

We think our 10-year replacement plan is at about the right level. Even with a lot of work on infrastructure, we're not going to abandon this. The plan includes:

- Spacer dampers
- Poles -- program calls for replacing 2,500 per year of our 77,000 wood poles. We've been doing about 1,600. Replacements are limited by resources, but also often by outages.
- Breakers -- replacements not always due to fault, but also as loads grow or impedance is reduced, their interruptive capability is not sufficient.
- Our $10 million in emergency replacement budget is used mostly on transformers (takes about 18 months to get a new transformer). Actual expenditure runs about $6 million.

We appreciate your support for our quest with Congress to get additional borrowing authority.

Operations & Maintenance: "Where we are -- Where we're going"
Fred Johnson, Vice President, Transmission Field Services

Ten to 15 years ago we had a well-defined maintenance program. It was time-based and on a scheduled preventive maintenance program. We had well-qualified people. We would request outages 24 hours to 72 hours in advance and get them. Our first choice was to take equipment out for maintenance.

Life has changed.

Today we make outage requests 45 days in advance for review and schedule the outage 30 days ahead, if we can. But within 24 hours of the outage, system conditions could change. Our ability to get skilled workmen has changed. The system is not gold-plated any more. These are things that influence our program levels:

Keys to our success (*p. 2*)
Reliability: My job is to ensure we have a reliable system until this infrastructure program is built out. Reliability tops our chart of Keys to Success. A line that touched a filbert tree near Albany, Oregon on August 10, 1996 caused the largest blackout in US history. It also caused us to rethink system reliability.

Availability: We're the delivery system for your product and needs. After the energy crisis we woke up to a brave new world. Before we could always take outages when we needed them, but not in the world we have today.

> Example: Spacer damper replacements (about 400) on a line along the Snake River. We planned to take a 7-day outage, 12 hours per day, and have 40 of our people work on it. We began requesting an outage in January 2001 for March. But there was a lot of runoff and a lot of energy to get out of the area, so we postponed the outage to July. Then the California Energy Crisis happened, so we postponed the outage to September. California Stage Two energy alerts caused us to postpone the outage to

Oct. 1. The day before the outage Puget Sound Energy asked us to postpone it again so they could get energy from Coalstrip to the head of the interties and send it to California. Due to the need to ensure reliability, we had to take the outage. PSE said they lost $6 million in foregone revenue in those seven days.

Our customers do not like any part of our system taken out. We're trying to find ways to do our maintenance while the lines are energized. We're also working on system redundancy so when we need to take a line out there will be another path.

Safety: We have one of the lowest accident frequencies among US utilities (about 1.1 injuries per 100,000 work hours). Worker safety is a strong ethic.

Efficiency and productivity: We talked to you in 1999 about Reliability Centered Maintenance. It's a process that looks at equipment failure frequencies and the consequences of those failures.

Employee development: With new practices and techniques, we need to train the existing workforce. But we also have an aging workforce. 40% of my employees are 50 and older and are eligible to retire in the next five years. It's also difficult to find skilled people, especially substation operators and electricians. We've made a commitment to our apprentice program with about 60 apprentices in the program at any given moment.

Operations & Maintenance -- chart (*p. 3*) -- $66.1 million for maintenance and $30.6 million for operations goes into our annual budget (FY2001 actual) to maintain TBL's nearly $4.2 billion plant.

O&M History and Projections -- graph (*p. 4*) -- See appendix, *pp. 24 & 25* for more detail.

- We reached a low of about $60 million in 1997.
- In 1999, we talked about how we had cut too far. We went to minimum crew sizes. Those cuts turned out to be too deep.
- This graph shows a slight build-up beginning in FY2001. Two reasons are vegetation management and rights of way clearing. We are on a five-year program to ensure access to our sites.
- FY2002 will be less than shown on this graph due to budget cuts we have already taken.
- FY2003 is an extension of FY2002.
- FY2004 -- this is the full program as a result of bottoms-up review.
- FY2002-06 are projected, not actual numbers. There is a slight disconnect because we tend to under spend our budgets.

Our costs are rising as we bring on about 700 miles in new lines and a number of new 500 kV substations (*p. 5*). G-1 through G-9 could all be added in during this period. We have to keep the existing system going while building out. We're managing within a constrained system and it is more difficult to get outages. Scheduling work to maintain line availability pushes costs up due to more overtime and more travel.

We are trying to do more work with the equipment energized. But that takes more people. Typical line crew is six people, but to replace a deadhead insulator hot takes eight people.

Maximizing use of resources (*p. 6*)

- We have new work practices
- Focus on our core business, which is transmission, and that's why we're selling small delivery facilities to customers. We've sold about 100 so far and are in discussions with 100 more with customers who may buy the facilities or are choosing to continue to pay the delivery charge. We've offered a 3-year bridge strategy to help maintain the facilities after the sale.
- The shape of our workload is not constant. We do not staff for peaks. We talked about minimum crew sizes in 1999, but that hasn't worked as planned. Two problems: we're a federal agency and it takes about 90 days to hire a new employee and it is difficult to fill positions when we need them, which typically is in the summer.
- The size of our staff is based on our continuous workload. We supplement staff with contractor crews or additional people during peak times. Due to a recent agreement with the unions, we can now use mixed crews (contractors) in particular crafts.
- Bundling has to do with both availability and efficiency in the way we use resources. We integrate both maintenance and construction work plans. If we have to replace a breaker, we plan other work that could be done at the same time.

We built our budget from the bottoms up (*p. 7*), determined what we need and then what we could cut. In that process, we found $11 million we could cut in these areas:

- Service contracts. Since 1996, we've worked hard on brush clearing and our right of ways are in good shape right now. We will take some risk and delay some of this work.
- Non-electric maintenance and substation work includes painting, fencing, etc.
- Delay in hiring -- Our budget accommodates 950 people. We are at 918. If we can manage through these lapses, we will get some savings. Also, given the labor force available, it would be difficult to get to 950.
- We'll do more on the job training and a little less travel to one of two training centers (Hammer and Ross).

FY2002 Resource Breakdown -- chart (*p. 8*) -- This chart shows where our money goes in O&M. About 77% of the budget pays for people, either staff or contractor services. We are strategically located in our 300,000 square mile service territory, but we still have to travel to the facilities. 14% goes to expendables, 6% to training and travel (60% to travel) and 3% goes to garbage, other utilities and rent.

Staffing History and Projections -- graph (*p. 9*) -- This shows changes in staffing levels for O&M and for Field Services work on some capital projects (substations). We peaked in 1993. In 1995, we had 700 people in O&M and 230 in construction. We flattened out by 2002. By 2007, we will have 630 in O&M and about 300 in construction.

My group also does substation construction work and there are increases in that due to the infrastructure projects.

Reliability important (*p. 10*) -- Until the infrastructure program is complete, we will have to continue at this level. We've been using reliability-centered maintenance for about five years and it is still good for us.

Availability (*p. 11*) -- Overtime increased 57%, much of that due to off-peak work. Example: A line in eastern Oregon was damaged by a lightning strike July 24, but when the TBL tried to repair the 230 kV line, voltage in LaGrande dropped to about 200 kV. The outage had to be taken late that night.

Line Availability FY93-FY2002 -- graph (*p. 12*) -- Illustrates the issue of availability on 209 of TBL's most critical lines. This graph tracks planned outages. For the last three quarters, transmission line availability has been at 99.5%.

Other pressures on our O&M budget (*p. 13*) includes work in our right of ways. These issues (environmental -- e.g. new fish-friendly culverts) are not always core electrical work, but we still have to deal with them. Another is our 5-year access road program.

Financial Assessment
Chuck Meyer, Vice President, Marketing & Sales

My group handles all of TBL's commercial activities. I've put this presentation together in such a way to show you our financial health and to put our program level expenditures in context. In addition, I will try to point out where some of the additional costs are and where we've made some cuts.

FY02-03 Rate Case -- table (*p. 2*) -- This table is to provide context to the Programs in Review process. The last time we did this in 1999 was for the FY2002-03 rate case and then we settled the rate case.

The good news is that in FY01 revenues were up significantly from the rate case. During the California energy crisis we moved a lot of energy, so that was a good financial year for Bonneville.

In addition, depreciation and interest came in lower than budget. That is due to having overforcasted the amount of plant in service and to the lower interest rates available during this period. We ended the year with $43.5 million net revenue. Yet, we settled the rate case with the expectation that we would basically break even.

Budget Process (*p. 3*) -- We take the issue of Bonneville's financial health very seriously and we've scrubbed our numbers to get as good an estimate of our budget as possible. Since we put the FY02 budget together in the summer of 2001, we have reduced that budget twice. Anything we can do to bring transmission rates down or hold them even will mitigate for a rise in power rates.

We completed bottoms-up review of the FY02 budget and took it into a strategic planning session at the end of May. The result was to do it again. We decided we could live with that FY03 budget in FY04. For our FY05-06, we are using the FY04 escalated by 2.5% inflation each year.

Keeping costs down (*p. 4*)
We reduced FY02 by 6.9%, although we will still spend more money than we originally thought in the rate case. FY03 is reduced by 9%.

Future of TBL Expenses, chart (*p. 5*) -- This is the TBL's projected income statement for FY2002 through FY 2006.

- FY2002 we're looking pretty good. If there is a bias in the numbers it is to the conservative side and could actually end up with a little higher operating revenues. We're three-quarters of the way through this year and I'm very confident revenues will be higher than $701 million. Expense spending, however, is more than the rate case, but it will not be higher than shown in this chart. It is possible that net revenue of $17.7 million could be as high as $27 million. It depends on the market conditions.
- FY2003 -- We believe we will continue to sell transmission. About 4,800 MW in new generation is now online or under construction. Operating expenses are largely the same as FY2002. It is further off in time, but we are still expecting about $41.3 million in net revenue.
- FY2004 -- We think we'll be in the same situation, but a little less dramatic. There is the possibility that we won't need a rate increase, or at least not a very significant increase, on Oct. 1, 2003, which is the beginning of FY2004.

We plan rate case workshops in August and perhaps into October to discuss what the TBL will need during the next rate period. There still are some issues that need to be tied up.

- The agency cash issue.
- We still don't have Congressional approval for additional borrowing authority.
- We may have to put on the table some type of revenue financing to produce the dollars we need for the infrastructure projects.
- In the last rate case we settled on who redispatches federal resources. The PBL agreed to do short-term redispatch as long as it resulted in no additional cost. Will that continue? The answer may cause some people's rates to go up, while others won't be affected at all.
- Some parties may want us to revisit the cost allocation issue. We settled in 1996 (our first rate case) and in 2001, so we haven't dealt in a rate case setting with the cost allocation issue.

Regardless, we have to have to go through the 7(i) process and file our proposal with FERC, even if we don't plan to change our rates.

Revenues -- chart (*p. 6*) -- Our long-term sales are higher than predicted in the rate case, but our short-term sales are down. Those that bought a lot of long-term transmission have now created a secondary short-term market to sell off some of that excess (required to be at prices at or lower than what they paid TBL). That, I believe, has cut our short-term sales.

Costs (*p. 7*) - Areas where costs are higher/lower than FY2002 rate case:

- Transmission Sales and Marketing functions are more. Increase in marketing and scheduling due to huge increase in volume. We're making a major effort to automate all contracts, largely to speed up the billing function and speed up transactions.
- Transmission System Maintenance is almost $10 million more
- Corporate and shared services, that part of BPA that provides services to both TBL and PBL, is $26 million higher.
- Transmission System Development is about $3 million less
- Depreciation is substantially lower
- Interest rates are lower.

TBL Capital Profile FY2002 through FY2006, chart (*p. 8*) -- The black line shows what it costs just to keep everything working, the traditional programs. You can see how dramatically that will change with the infrastructure projects over time.

Capital Spending Vs Plant in Service, graph (*p. 9*) -- This shows how the infrastructure program will affect transmission prices. We don't put capitalized projects into rates until they are energized. They don't start coming into rates in a meaningful way until FY 2005.

The projects will accommodate 8,000 MW to 12,000 MW more power. Our break-even point -- where sales pay for all G-20 projects -- is 5,500 MW. If we can sell that much, the infrastructure program wouldn't contribute to higher rates. 4,800 MW of new generation is coming on line by June 2003. Also, it doesn't have to be new generation. Some projects will relieve congestion and that pent-up market will add to transmission sales. The power market should be benefited and it shouldn't cost you any more money.

On one side of the 5,500 MW, power prices will fall. On the other side, they may need to rise.

We're also looking at different ways to finance infrastructure projects. We will likely receive $700 million in borrowing authority from Congress, not the $1.3 billion we need. We can't seek alternative financing for all projects. The Coulee-Bell 500 kV transmission project is to serve contracted load. We can't get someone else to pay for it.

However, if we do a line for new generation, we have the authority to charge that developer a marginal rate if the cost of the project is greater than our rate. A developer can prepay transmission revenues to help pay for construction. There would be no cost transfers to public power.

Even with the new infrastructure projects, TBL is projecting positive net margins through FY 2004. Current rates expire Sept. 30, 2003. TBL is having rate case workshops in August and September, and maybe in October. The earliest it would release an initial rate proposal would be in November. The latest would be in January 2003.

So, what does all this mean for rates? The answer hinges on:

- How we finish FY 2002.
- Agency cash position.
- Redispatch changes. Since 1996, PBL has provided very limited redispatch to help solve congestion problems. That issue could be a reason to raise rates and could have revenue requirement implications.
- Allocation of costs. TBL has settled both rates cases since becoming a separate business line. Some customers may not like the way costs are allocated.

Appendix

TBL Expenses (*p. 14*) -- Corporate and shared services, that part of BPA that provides services to both TBL and PBL and accounts for the administrator's office, attorneys, printing, etc., is $26 million higher. It also includes IR Support -- the business system, building management and cyber security measures, among others.

The region had just completed a Comprehensive Review of BPA's future. They recommended a reduction in BPA overhead. The ink hadn't dried on the review when TBL put the rate case together. We even doubled the numbers, but that turned out to be way too low. The rise in these numbers levels off in FY 2002 and later. You should see something similar in PBL's budget.

TBL will still be one of the lowest cost Northwest transmission providers (*p. 29*). --. Our costs contribute about 3 to 4 mills per kWh to your total cost of delivered power.

Account Executive

- Comment period for Programs in Review closes Sept. 16, 2002.
- The Administrator will determine the program levels in a closeout letter in October.
- Rate case workshops begin in August. Initial rate case proposal not expected until at least November.