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CONGESTION MANAGEMENT
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ALBERTA ENERGY AND UTILITIES BOARD
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A Proposal for Long-Run and Short-Run Congestion Management in Alberta

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Submitted on behalf of
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Evidence Regarding
Congestion Management in Alberta
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1. Preamble

"Congestion management" (CM) means dispatching around constraints when congestion is present. *Efficient* congestion management minimizes the cost of the dispatch. In Alberta, congestion management could come to mean *congestion prevention*. I have encountered that meaning of CM nowhere else. In the U.S., regulated utilities sometimes adopted this approach, but it was not called "congestion management." The term used was "gold plating."

Perhaps "prevention" is too strong. The TA has stated that it will *not* eliminate *all* congestion. The loss of a line will not usually cause congestion, but occasionally it might. Due to long lead times when constructing lines, a generator might face some temporary congestion. In other words, congestion may occur by accident or because of imperfect foresight. To discover the essence of the TA's CM policy, consider a simple hypothetical example. A good policy should work in a simpler world.

Two equal load centers, **A** and **B**, are connected by a transmission path of considerable length. All generators at load-center **A** have a cost of $27/MWh and all at **B** have a cost of $30/MWh. Suppose an optimal locational incentive (LBC) induces sufficient generation at **B** to serve all of **B**'s load not served by the 1000 MW path from **A** to **B.** Both load centers have a peak load of 6000 MW and an off peak load of 3000 MW. All is satisfactory until the generators at **A** point out to the TA that they have 2000 MW of spare capacity at night, are in merit, and would like to serve off-peak load at **B.** After checking Principle 2, the TA builds a 2000-MW 500-kV upgrade from **A** to **B**.[1]

But what about the cost of the line? That has not entered the discussion because it is not part of the TA's policy to consider it. The TA intends to build the cheapest line possible when it must build one, but the decision to build is a matter of Principle 2 and not a matter of cost.

To satisfy an economist's curiosity, let us check the cost. After careful analysis, suppose the TA finds the cheapest line has an amortized cost of $87,650,000/year, or $5/MWh of transfer capability. The upgrade is used to serve off-peak load which, in this example, occurs for exactly 1/2 of the hours, so the line cost per megawatt transferred is $10/MWh. The savings in generation cost is $3/MWh for power purchased from **A** for **B**.

Without the upgrade, the system would have been congested for 4382 hours per year. The upgrade "managed" the congestion by keeping the region free of it.

[1] In the response to BR-EAL-01, Principle 2 states, "Generators and loads that have executed firm contracts will receive equivalent levels of transmission access service from the TA." The TA interprets "equivalent" to mean that any time a generator could profitably sell power to the Pool and wishes to, the necessary transmission will be available. This mirrors, but is not necessarily equivalent to, the required service to loads: any time a load could valuably buy power from the Pool and wishes to, the necessary transmission will be available. References to "Principle 2" assume the TA's interpretation of "equivalent."

The example corresponds to no real situation but serves to make a simple point. The TA's congestion management principles call for transmission projects that are not even approximately correct in some very simple cases.

[Instead of ad hoc "principles,"] this proposal recommends going back to basics—cost minimization and market forces. A design based on tested fundamentals is the best defense against unforeseen changes in circumstance. A perfectly competitive market cannot be designed for transmission investment, but market forces can be harnessed to keep costs in check, even if Alberta will no longer be the congestion-free province.

2. Fundamental Principles

Minimize the total cost of production and delivery and the Pool price will follow.

One principle of market design stands out as the most important—minimize the cost of production and delivery.[2] Maximizing the benefit of consumed power is another basic principle, but it will play no role in this analysis. Other, secondary principles help guide the search for minimum cost. The most important of these is to rely on the force of competition when possible.

When the cost-minimization principle is applied to the problem of congestion management (CM), four guiding principles follow:

Long-Run CM:	1. Minimize the total cost of wires, generation and outages.
Short-Run CM:	2. Define and allocate tradable transmission rights.
Risk Management:	3. Keep regulatory commitments. 4. Design to reduce commercial risk.

The first of these is most central to the present hearing and encompasses two unrelated trade-offs: The Reliability Trade-off and the Commercial Trade-off.

2.1. Long-Run Congestion Management

Reliability: Minimize the total cost of outages and wires.

The first goal of the TA should be to keep the AIES reliable, but this does not mean absolutely reliable at any cost. It means: increase reliability to the point where the savings from an increment to reliability would be less than the cost of that increment. Because reliability is very valuable, the AIES should be made extremely reliable. But there is a limit, and that limit is determined, however approximately, by total cost minimization.

Commercial: Minimize the total cost of energy and wires.

The second goal is to minimize the total production and delivery cost of power to Alberta's consumers. Build wires to the point where the generation-cost savings from an increment to transmission would be less than the cost of that increment. While contemporary power markets do not have the ability to make the reliability trade-off, they do contain market forces that can be harnessed to minimize the total cost of generation and wires—to make the commercial trade-off.

Congestion means needing to use a more expensive local generator instead of a less expensive remote generator because the transmission line is inadequate.

[2] Economics suggests first that production and delivery should be efficient (least cost) and second that the product market be competitive so all cost savings are passed on. Attempts to circumvent this process and minimize consumer cost directly by pushing Pool price below long-run cost always have costly, unintended long-run repercussions.

There is a cost to using generation out of merit, but if it only happens for 10 hours per year and only for 100 MW, the cost will be small. If a path is congested for 6000 hours per year, an extra MW of transmission capacity will save money for 6000 hours per year. As transmission capacity is increased, the hours of congestion decrease the savings from another MW of line capacity also decreases, but the cost of another MW of capacity does not decrease. Eventually, when congestion has become a rare event, the savings will be less than the cost. Further decreases in congestion are not economical. (If the redispatch costs of congestion are small and the line cost high, savings will become less than cost long before congestion is rare.)

2.2. Short-Run Congestion Management

Congestion causes generators to be run out of merit order, but the cost of generation should still be minimized (given the transmission constraint). That is the purpose of short-run CM. It optimizes production given the existing system. Long-run CM optimizes the set of wires and generators. One has a time horizon of hours, the other, a horizon of years.

The key to short-run congestion management in a system without locational energy prices is tradable transmission rights (TTRs). Consider, for example, the TA's proposed system of non-tradable rights for use when a line is late in completion. If congestion occurs, the new generator is curtailed while the old generators are allowed to run at full output. This rule confers implicit injection/transmission rights on the old generators, but these rights are not tradable. If they were, the market would correct any dispatch errors caused by arbitrarily curtailing new generation.

Suppose the new generator has a generation cost of $20/MWh while some of the old generators have dispatch costs of $30, $40, and $50/MWh. Suppose the Pool price is $55/MWh. The new generator would pay up to $35/MWh for the right to generate, while the old generators would sell their rights for any price above $25, $15, and $5/MWh respectively. When selling rights, the least efficient generators can always underbid all others and still make a profitable sale. The exact price depends on how many expensive generators there are and how competitive they are in selling their rights, but the exact price does not matter. What matters is that the most inefficient generators will sell their rights first. Perhaps the rights would sell for $8/MWh. The old $50 generators will make $3/MWh more than if they had generated, and the new cheap generator will supply power for $30/MWh less than the old $50 generators. That is efficient.

Tradable rights allow the ***market*** to manage congestion.

Simply making the rights tradable allows the market to turn an inefficient system of curtailment into an efficient system. When it is allowed to, the market fixes regulatory problems. In this case, the dispatch becomes perfectly efficient.[3]

Pro-rata curtailment is always inefficient, but if generators can trade their remaining rights to generate, the cheap generators will end up with the rights and

[3] The savings in production cost may or may not be passed through to consumers immediately. If the only $50 generator sells its rights to the new $20 generator, then the Pool price would drop to $40, and the consumer savings would be enormous. If there are two, and one $50 generator remains in the market, the Pool price would remain unchanged. Economics predicts that, in the long run, consumers must pay the cost of production, but if the market is competitive, they will pay no more. Lowering the long-run cost of production lowers the long-run cost to consumers.

the market will minimize the cost of production. When transmission is built to eliminate all congestion (at any cost), there is little need for TTRs, but when congestion is optimized, there will be congestion and it will need managing. Without locational energy prices, tradable rights allow the market to manage congestion.

2.3. Risk Management

Risk is costly. Suppliers in a risky market must pay more for their capital—a risk premium as it is called. There are many sources of risk and the principle of cost minimization implies these should be minimized, but only to the extent that is cost effective. This trade-off cannot be made precisely, but it is important to recognize the sources of risk so that they are not ignored when they can be easily reduced and are not increased without reason.

Congestion itself imposes risks, so it is important to make long-term congestion rights available to the extent possible. In some cases, these can be conferred on those who implicitly have them. In other cases, they can be sold to help pay the cost of transmission investment. If a generator must build a line, the risk of this project will be greatly increased if it must build more transmission than it needs and speculate on selling the excess in the future. Congestion and line-building risks are commercial risks that can be mitigated by a good market design.

Risk:
Minimize the cost of regulatory uncertainty.

Regulatory risk can result from rule changes that cannot be anticipated and happen after large costs have been sunk. The regulator can eliminate most risk of this type simply by following through on explicit commitments and clear implicit commitments. The TA has implied that existing generators have rights to the present system that new generators do not.[4] At the same time that TTRs are defined clearly and made tradable, existing rights of generators should be vested. Tradability will ensure an efficient outcome.

3. Overview: A System of Congestion Management

The principle of cost minimization and the four guiding principles of CM together with institutional constraints imply a narrow range of solutions to the CM problem. This section sketches a solution that tempers the economic principle of least cost with the more human principles of simplicity and minimal disruption. It consists of the following four components:

1. Reliability projects: the TA plans them and the system pays.
2. Commercial upgrades: market participants plan them and pay.
    a. The TA prices and sites them.
    b. Facilitation: piggyback on reliability.
    c. Facilitation: purchase only what's needed.
    d. Motivation: no free transmission rights for hookup.
    e. Motivation: paying for lines buys transmission rights.
3. Board approval required for both.
4. Tradable transmission rights.

[4] "Interim access capacity limitations occurring during the lead time required to expand the system will be satisfied by constraining the last customer(s) to execute Construction Commitments Agreements." (See BR-EAL-01.)

3.1. Reliability Upgrades

Reliability means not having to curtail load involuntarily. NERC considers a transmission system reliable if it causes blackouts for only 1 day in 10 years. This rule of thumb embodies an implicit trade-off between the cost of improving reliability and the cost of involuntary curtailments. Reliability must ultimately be defined in physical, not commercial, terms.

This basic standard is translated, for implementation purposes, into engineering standards such as the single-contingency standard. The engineering standards are essential for efficient planning, but they are not fundamental. Customers do not care about contingencies and their probabilities; they care about how often they will lose power. It is the job of the engineers to translate a level of service reliability into the appropriate engineering standard.

Reliability upgrades are the TA's meat and potatoes.

Before load is involuntarily curtailed, the energy price will be raised to the point where every available generator is willing to run. The question of reliability is simply a matter of whether there are enough generators and lines to supply the needed power. That the TA is responsible for this trade-off is well established. Reliability was the entire motivation for the TA's SERP proposal. Voltage collapse is a reliability issue, and as was acknowledged by all, the TA's job is to see it does not occur. Whether the TA finds that the least-cost solution for adequate reliability is an LBC process or a line-building process, the purpose is the same—a reliable system. The sensible way to pay for system reliability is with a per-megawatt-hour system charge. This is already in place. The present proposal suggests no change in the TA's responsibility to provide for system reliability and no change in the way it is to be paid for.[5]

3.2. Commercial Upgrades

Commercial upgrades are any that are not for reliability.

Commercial upgrades are those that are not reliability upgrades. If the TA can decide what is needed for reliability, then it has already solved the problem of what is a commercial upgrade—anything else. The TA was in some doubt, during the proceedings leading to Decision 2000-1, as to whether a distinction could be made. It now acknowledges the existence of export upgrades that are purely commercial. Just as a generator may need a line to sell its power to the U.S. at a profit, so it may need a larger line to sell its power to some part of Alberta at a profit.

For example, on peak there might be only 1800 MW of excess capacity in the North, so a N–S line larger than 1800 MW might serve no reliability purpose. However, off peak, 2400 MW might be available due to the reduction in northern load. If all of this generation were cheaper than any southern generation, a 2400 MW line would be useful off peak—not for reliability purposes but for economy trade. Upgrading the line to sell off-peak economy energy would be a commercial upgrade. There is no reason for the TA to attempt to discover such upgrades. It need only decide what is needed for reliability.

Deciding which commercial upgrades are sound is a job for the market, not for a central planner.

Determining what is needed for reliability and what is not is the TA's primary responsibility, and that answers the question of which upgrades are commercial. Deciding which commercial upgrades are worthwhile is far more difficult and would force the TA into a central-planning role. The purpose of

[5] It would be useful to simplify bookkeeping by dropping the pretence that generation is paying 50% of the cost, as this cost is all passed through to load. The only exception is that native generation is disadvantaged somewhat relative to external generation.

deregulation is to avoid this, and the TA has rightly resisted it. Instead, *market participants* should decide which upgrades are commercially sound. Arranging this is not a trivial matter, but with a good arrangement, market participants will have better incentives than the TA and they always have better information.

The key to this proposal is a mechanism for motivating market participants to build lines when the lines save money, i.e. when they minimize total generation and delivery costs. This is simply an extension of the connection policy that is already in place. If a single generator were to locate 500 miles from the system because that reduced its cost of fuel, the generator would have to pay its own connection costs. This would force it to make the right economic decision. Including both the cost of the line and the cost of generation, could it still make a profit? This is a question the generator should answer and not the TA.

The proposed mechanism is much the same. If a generator or a load believes a new line will lower its costs, then it should be willing to pay for the line. If it knows the savings from the line would be less than the cost to build the line, it will not be willing to build it. The only way to find out if it is willing is to make the beneficiary pay for the line. This is the way markets work and is what the proposed process attempts to replicate.

It is important for Alberta's consumers and for Alberta's generators that economically sound commercial lines actually will be built. To make this happen, market participants must be motivated to build, and the difficult process of transmission investment must be facilitated. Several policies for motivation and facilitation are suggested and discussed in Section 4 but are listed here as part of the overview.

Making Sure Economically Sound Lines Will Be Built

Facilitation:	(Solve the last-straw problem)	A new generator need only pay for what it needs.
	(Allocate fixed costs)	Commercial upgrades can piggyback on reliability.
	(Solve right-of-way problems)	TA carries out projects under Board's authority.
Motivation:	(Provide insurance)	Grant perpetual transmission rights for new lines
	(Solve 2nd free-rider problem)	No free transmission rights.

3.3. Board Approval

Reliability upgrades are primarily paid for with a per-MWh system charge, and while this charge is formally placed half on generators, economic theory and common sense indicate they will pass it on to load. To the extent commercial upgrades can be re-labeled as reliability upgrades, they will be essentially free to the market participants that desire them. There will remain a need for public scrutiny of the process. For this reason, all transmission upgrades should require Board approval and should be open to challenge.

3.4. Tradable Transmission Rights

Tradable transmission rights (TTRs) play three distinct roles in this proposal. The lack of TTRs motivates new generators to build lines. Granting TTRs to those who pay for upgrades provides an additional motivation to those who pay for lines. The trade in TTRs restores efficiency to the dispatch in the face of congestion and uneconomic curtailments.

Without tradability, the market cannot participate.

Transmission rights are not an innovation. What is new to Alberta is their tradability. While they will still be partly controlled by regulation and administrative procedures, tradability introduces market forces that will make use of the TTRs in the following ways.

New Generators and the Lack of TTRs

Once the transmission system is congested, TTRs will be valuable and all available TTRs will be purchased. When a new generator joins the system, it will be able to sell into the Pool at most times, but when faced with congestion it will need to purchase a right or curtail output. The value of transmission rights measures the value of an increment of new transmission capacity. If the new generator can buy TTRs cheaper than it can build a line, it will do so and this will be the cost-minimizing decision. If it is cheaper to build the line, it will do that and that will be the appropriate decision. In this way the lack of transmission rights for new generation and the market value of transmission rights combine to send reasonably accurate signals for investment in new generation and in new lines.

New Rights for New Lines

When a generator does pay for a line, it will want something in return. Since it will not own the line, a perpetual TTR for the use of the line provides the other half of the motivation to build. Because the right is tradable, even if the TTR owner's generator is out of service or out of merit order, the owner may still derive some value from the line it paid for. The right will also guarantee that the owner can use the line at no cost no matter how congested the line may be.

Tradable Rights for an Efficient Dispatch

When congestion is "managed" by elimination, an efficient dispatch is achieved by dispatching in merit order. When congestion is optimized (total cost is minimized) then congestion must actually be managed (as it is in the rest of the world). Congestion is something that occurs in real-time and when it occurs, it should be managed by dispatching at least cost, taking into account the binding transmission constraints. This can be done with locational energy prices, but if it is not, it can be done with tradable transmission rights. In a system with few constrained paths, this may be perfectly adequate.

4. Motivating and Facilitating Commercial lines

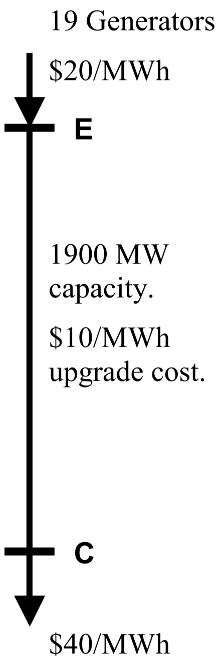
4.1. Motivating Commercial-Line Investment

If all market participants can "free ride" on transmission provided by others, they will not be motivated to build new lines. This problem is the central difficulty preventing a fully competitive design for a transmission-investment market. No complete solution will be attempted, but a partial solution should prove adequate when combined with various policies to facilitate and encourage investment. No claim is made that the result will be optimal, but I believe the outcome will be superior to what could be expected from casting the TA in a central-planning role for commercial investment decisions.

If everyone has equal rights to new lines, private investment is discouraged.

The Basic Free-Rider Problem

To illustrate the free-rider problem and the proposed partial solution, consider two locations, E and C, connected by a transmission path, NS. Suppose there are 19 identical generators at E and the path is just adequate to carry all of the power they can export to C. Suppose the energy price at E is $20, while at C it is $40/MWh, and suppose that line expansion costs $10/MWh. For simplicity, ignore load fluctuations and assume the line is fully utilized at all times. (Note: The cost of the line should be understood first as an annual cost that describes the cost of financing the line and then as that annual cost divided by the number of hours in a year. This makes it comparable to the cost of power.)



In this example, if a new generator, with a 100 MW capacity, is built at E, there will be 100 MW of $20-power available at E that cannot be transmitted to C. By upgrading the line, it could be transmitted at a (long-run) cost of $10/MWh. Thus, the total cost of power delivered to C would be $30/MWh for a savings of $10/MWh compared with not building the line and generating the power at E. In this case, the line should be built for commercial reasons.

If the policy were to pro-rate the use of the line (suppose it is a 1900 MW line), the 20 generators would each be allotted 95 MW of line capacity. If the new generator were to expand the line by 100 MW to accommodate its generating capacity, it would increase its ability to export to C by only five MW. Clearly, it would not upgrade the line. Similarly, no other generator, acting alone, would find the expansion worthwhile.

If all 20 generators paid for the expansion collectively and shared the cost evenly, each would pay only $50/h and receive a 5 MW increase in their share of the line. They would pay only $10/MWh of use. Collectively this makes sense. The line should be built, and if it were built collectively, it would be individually profitable. But no such coalition could hold together.

What if one generator decides to abandon the coalition and not contribute while the others proceed with a 95 MW upgrade for their own use? The uncooperative generator will find the 95 MW of new line pro rated. It will receive the use of an additional 4.9 MW of capacity at no cost—it will get a free ride.

Solving the Basic Free-Rider Problem

The basic free-rider problem can be solved by giving rights to those who pay for the upgrade. If the 19 cooperative generators are given an exclusive right to their 95 MW upgrade, they would each get to use 5 MW of new capacity. The remaining 1900 MW of old line would be pro rated with each of the 20 generators getting 95 MW. The uncooperative generator would get no use of the upgrade and the cooperative generators would get what they paid for.

A Second Free-Rider Problem

If new generators have equal rights to old lines, private investment is not motivated.

There is a second free-rider problem caused by new generators obtaining 95 MW of valuable transmission rights for free. This gives new generators an incorrect incentive to build where there is congestion. Moreover, the incentive will be strongest in the worst locations and non-existent in the best locations. Reconsider the prior example and a new 100 MW generator with a $35/MWh cost of generation that locates at E. It will receive a pro-rata right to inject 95 MW of power. Assuming a market-base TTR system, these rights are worth $10/MWh because they act as a substitute for upgrading the line. Even if the new generator did not sell its rights for $10/MWh, it could still use them to make $5/MWh by selling its $35 power to load at C where the price is $40/MWh. Thus the $35/MWh generator finds it profitable to locate at E.

Such an investment in generation is inappropriate. If the generator runs, it will displace $20 generation, and if it sells its pro-rata rights it will be earning a profit simply because it was given valuable rights for free. If the supplier faced the true cost of supplying power to C, i.e. if it had to pay for the line to get its power to market, it would not have built generation at E.

Solving the Second Free-Rider Problem

All possible existing rights should be vested or sold.

The solution to the second free-rider problem depends on all transmission rights being owned, and new arrivals not being given valuable rights without charge. Existing rights should be allocated in two ways: by vesting them in existing generators or by selling them. The TA's proposal to curtail new generators when necessary before it has finished constructing a line, suggests that existing generators have implicit rights to the current system. Regulatory commitments both explicit and implicit should be kept. This reduces regulatory risk. There will be times when the existence of an implicit commitment is unclear and disputed, but this should not be allowed to interfere with granting explicit rights where past practice clearly indicates a regulatory commitment. Ambiguous cases should be arbitrated by the Board.

Some rights will probably not be allocated in the vesting process, and new rights will become available through transmission upgrades, these rights should be sold by the TA in a transparent process. The proceeds can be used to cover part of the cost of reliability upgrades.

The second free-rider problem is solved by not giving new generators valuable rights to existing transmission simply because they show up on the system. In addition, they must not be automatically given the right to a transmission upgrade if needed. In effect, the TA's proposal gives out rights to upgrades. A new generator may have to wait awhile to receive them if the line takes longer to build than does the generator, but this is a minor annoyance. If either existing rights are shared pro rata with new generators or new generators are guaranteed new lines, then they obtain valuable rights just for showing up. This encourages investment in generation in locations that will require transmission upgrades and it takes away the incentive for new generation to pay for those upgrades. Ironically, the worse their choice of location, the more valuable the rights they receive. For example, if they show up in Calgary, the right they receive is worth nothing.

4.2. Facilitating Commercial-Line Investment

Solving the "Last-Straw" Problem

Returns to scale undermine a competitive market.

The TA should average out the costs.

The above example greatly simplifies reality. This does no harm because any problems remaining, the ones examined, must be fundamental, but other problems were swept under the rug by the simplifications. One of these is the "last-straw" problem. As new generators come on line and the AIES becomes congested, that congestion will eventually reach a point where no new generators can be profitably added without a line upgrade. Then the next generator to build will be forced to pay for a line upgrade. Because lines come in discrete chunks and not megawatt by megawatt, the upgrade will typically be larger than needed. This will open the door to more new generators, but the one that pushed the system over the threshold (added the last straw) will have to pay for the entire upgrade.

To solve this problem, cooperation is needed between the last-straw generator and those that immediately follow it onto the system. What would induce such cooperation? Suppose the last-straw generator needs about 100 MW of line capacity and a 100 MW upgrade would cost $800/h, while a 300 MW upgrade would cost $1000/h.[6] If the TA were given the choice, it would build the 300 MW upgrade, but the last-straw generator might prefer not to donate $200/h and 200 MW of spare capacity to its competitors. This leaves it with a choice of building a very expensive ($8/MWh) small line or not entering the market. Neither outcome is socially desirable.

In this case the right solution is probably for the TA to build the 300 MW line and sell the new generator a 100 MW upgrade for $333/h, one third of the total cost. This decision requires judgment but less judgment than if there were no market participation in the decision. If a new generator wants 10 MW of a 500 MW line, the TA would not be likely to suggest building the line for a mere 2% contribution to the cost. The more likely the TA is to be able to sell the remaining line capacity, the more willing it should be build an upgrade that is only partly needed. If there is little promise of selling the remainder of the upgrade, the TA should not undertake it. It would reduce uncertainty in the market place if the Board were to adopt some standard for the extent to which the TA should speculate by building line capacity in excess of what has been purchased.

Share of line	Share of total cost
0%	25%
33%	50%
66%	75%
100%	100%

The Board may wish to adopt a rule of thumb regarding cost sharing as guidance for those proposing to buy only part of an upgrade. For example, the purchaser could be required to pay (3S+1)/4 times the total cost of the line, where S is the purchaser's share of the line. Some results of this formula are shown at the left. If the system is to take on the risk of building a line that is not yet wanted by market participants, this formula compensates it for taking that risk. This would motivate the purchaser to find partners and to take on some of the risk. It can always buy a little more than it needs and sell the rights if it believes the line really will be needed.

The unpurchased portion of the line should not be given away. If it is, there is no hope of recovering its cost and it will recreate the last-straw problem. New generators will always wait for some other generator to pay for too big a line. Moreover every generator that does purchase an upgrade will purchase the smallest possible upgrade, knowing it can use the remainder of the line anyway. If a 100 MW upgrade is purchased and a 200 MW upgrade is built, the TA and the Pool must treat the upgrade as if it were only a 100 MW upgrade. There is some inefficiency in leaving part of the line unused, but this inefficiency is necessary to create the proper incentives.

> When possible, allowing commercial to piggyback on reliability is the best way to solve the returns-to-scale problem.

Allocating Fixed Costs of Transmission

The root of last-straw problem is the fixed costs of building a line. In the above example the cost of the line was $700/h + $Q/h, where Q is the line capacity in MW. The $700/h term is a fixed cost because it does not depend on the size of the line and the $Q/h is a variable cost because it is proportional to the line's capacity. (This is different from the fixed and variable costs charges for lines which are fixed and variable relative to the quantity of energy transmitted

[6] The cost of a line includes the cost of maintenance.

rather than to the capacity of the line.) Real line costs are much more complex, but they often have the property that twice the capacity is less than twice as expensive. This fact can be used to subsidize commercial lines without costing Alberta's consumers any extra.

Assume a reliability upgrade of 1000 MW is optimal and that the cost of the upgrade is \$4000/h + \$Q/h, for a total cost of \$5000/h. If market participants wish to purchase an upgrade to the same path while the reliability upgrade is being planned, they could purchase an additional 1000 MW for a cost of only \$1000/h. This would cost consumers nothing and would send a more accurate marginal cost signal to those planning the upgrade.

5. Tradable Transmission Rights

In most cases, generators would not purchase wires; they would only purchase the rights to use the upgrades. More importantly, they cause the upgrade to be built. Having the new line may mean there is little congestion and the right is worth very little. But the line is still valuable. For example, when a generator builds a line to connect to the grid, it earns no money on its implicit right to use the line, but the line itself has great value.

In a more competitive setting, the main value of an upgrade will be having the wire available to bring power to the desired market, but transmission rights will have some value. The more congestion, the more value they have. It is important to remember that TTRs are not the main reward for building transmission.

As explained in the first part of Section 3, TTRs solve two free rider problems. Because existing generators have a combination of vested and purchased TTRs, new generators will not be rewarded with valuable rights merely for showing up. Because upgrades are rewarded with TTRs, those who don't help pay for them will receive little benefit from them. The existence of tradable TTRs also assures an efficient dispatch.

5.1. Defining Transmission Rights

Markets depend on well-defined property rights.

For TTRs to serve all three purposes effectively, they must be defined carefully. Tradability in particular requires a careful definition. Some types of rights are locationally specific. For example, the right to inject a megawatt at C cannot be used by a generator at E. For maximum tradability, rights should be defined as pertaining to as wide a zone a possible, but the physics of transmission imposes definite limits.

Many kinds of TTRs have been proposed and used, with financial rights (FTRs) being the most prevalent. Typically an FTR for 1 MW form **A** to **B** gives a right to collect the congestion rent charged to a 1 MW flow from **A** to **B**. This is like insurance. If the owner actually does transmit a MW from **A** to **B**, it is charged the congestion rent for the flow and paid it for its FTR, so in essence the FTR permits it to ship power from **A** to **B** at no cost. Financial rights are most convenient, as they do not require real-time physical monitoring. Unfortunately, without locational energy prices, they are meaningless.

Both physical and financial TTRS are typically defined as corresponding to a flow of power with a beginning and an end. This is convenient because such flows can be judged as physically feasible or infeasible. This helps to set the proper limits on the set of rights that can be made available. The right to inject a

MW at **A** has no physically meaningful interpretation. It is impossible to inject a MW at **A** unless a MW is withdrawn somewhere else, and without knowing where "somewhere else" is, the power flow caused by injection at **A** is indeterminate.

Rights should mirror physical and economic reality.

A flowgate is a transmission path that has a realistic possibility of becoming congested, that is, of limiting the flow of power to a level below what is commercially desirable. The NS path could be considered a flowgate as could the line from Ft. McMurray to Edmonton. A physical flowgate right allows a generator or a trader to send power over the specified flowgate.

Thus, the most difficult TTRs to define are one-ended physical rights—injection rights. These are also the most commonly discussed rights in Alberta. Nonetheless, an analysis of the problem at hand indicates that a system of TTRs involving physical injection rights and physical flowgate rights could serve the required purposes while retaining Alberta's one-price Pool. Since it is only sensible to upgrade a path that is sometimes congested, all upgrades happen to flowgates. When a flowgate is upgraded, the purchaser would receive a corresponding flowgate right.

5.2. How to Design a System of Transmission Rights

When transportation is costly and production cost varies by location, the same commodity sells at different prices in different places. At least this is how pricing works in a competitive market and such prices are efficient.[7] Such locational price may be reflected, with more or less accuracy, by many different institutional arrangements.

Economics determines these locational prices precisely, but it does not determine a specific market design. It only provides tools for analyzing market designs. Alberta's Pool ignores this fundamental economic fact by specifying a single price. This would be reinforced by a transmission policy that attempts to make transportation free. In spite of these efforts to reform economics, the market has felt a constant need to compensate for the discrepancy between competitive prices as Pool prices. This need has given rise to generation being constrained on and constrained off "by transmission" and to the need for "locational signals" which motivated SERP. This need is currently being expressed through IBOC and LBC SO auctions. (These are for reliability.)

The key to designing a system of transmission rights that improves dispatch efficiency and sends accurate location signals for generation and transmission investment is to look to the economics of competitive prices. Consider a three-bus model of the AIES—approximate as this is, it is far more accurate than the reigning one-zone model. Call the three Buses F, E and C. Competitive theory tells us there should be three energy prices, but this is not allowed. By defining rights to deliver power at F and E, the system acquires two more prices, although energy still sells at one price (and all load pays that price). From the generation point of view, it is as if the price of energy at F and E is different than the price at C. If you have a right to inject at E and the market price of that right is $5/MWh and the Pool price is $50/MWh, you will produce if your cost is below $45 and you will sell your right if it is above $45. You will act as if the energy price at E

[7] For a description of competitive economic theory as applied to electricity markets see Chapters 1-5, 1-6 and 2-1, in Steven Stoft, *Power System Economics*, forthcoming by IEEE-Wiley and available now at www.stoft.com.

is $45/MWh. If you do not own a right, you will also act as if the price at E is $45/MWh.

The second step in designing rights is to add transmission rights that correspond to system physics. If you pay for an upgrade from F to E, you do not obtain the right to inject at F, you obtain the right to flow power from F to E. You can then buy a right to inject at E or a right to flow on to C if those are needed.

5.3. Putting the TTRs in Perspective

Lines will not be built to obtain transmission rights, but to bring cheap power to where it will fetch a higher price market. Rights assure investors they can use their lines as needed.

Most of the time, no rights will be needed, as the system will not be congested. When it is congested, most generators will have the rights they need. There will be a little trade in rights and this will establish the correct prices. If the owner of a right does not use it by injecting or flowing power, that tends to keep the system uncongested, which makes room for others to flow power without having any right. This makes exercising market power by buying up and withholding the rights difficult.

If the market is going to send signals that help determine the location of generators and which lines should be built, Alberta will need new tradable rights of some kind. An energy market with the same price at every location cannot do the job.

6. Procedures for Approving Transmission Projects

6.1. A Pure Reliability Project

The TA should continue evaluating transmission needs annually but instead of determining what is needed to make sure no generator in merit is ever curtailed, it should look only at the load-side of its criteria. Its reliability criteria (load-side criteria) should be made public and explicit.

The TA should continue to examine location-based generation incentives as well as transmission upgrades when determining the least-cost method of obtaining a reliable system. For parts of the system in which no commercial upgrades are proposed, the TA should propose the least-cost set of reliability projects, and publish these in the annual Transmission Development Plan. (For other parts, a combined project should be proposed. See Section 6.3.) The complete analysis on which this selection is made should be made publicly available well in advance of the relevant Board hearing. Because an incorrect evaluation of what is necessary for reliability can be used to subvert the commercial upgrade process, openness of process and clarity of standards are of utmost importance.

6.2. A Pure Commercial Project

If a market participant desires an upgrade to the transmission system, it should request an evaluation of the project by the TA. The TA should cost out the project both at the requested capacity level and at any higher levels that seem more economically sensible. The market participant can then choose one or more projects and for each a fraction of the capacity that it would purchase and a fraction of the cost it would pay. It may not offer to pay a fraction of the cost that is less than the fraction of the project purchased. These offers will then be presented to the Board along with its assessment of the risks involved in paying for the part of the upgrade not purchased by the market participant.

If the requested upgrade is simply an increase in the capacity of a planned reliability upgrade, the TA should evaluate the cost of the upgrade as the incremental cost to the reliability project caused by the upgrades increase in the planned capacity. This is not considered a combined project because it leaves the reliability project essentially unaltered.

6.3. A Combined Project

The TA should give credit for commercial contributions to system reliability, and these should be publicly documented.

If a market participant believes that an upgrade it requires would increase system reliability even though it is not an expansion of any proposed reliability project, it may request a combined evaluation. In this case, the TA should determine if the existence of the upgrade would reduce its estimated costs for reliability projects. To the extent it would, the upgrade project should be given credit when the cost of the project is evaluated. Openness and transparency is particularly important for the process of evaluating and approving combined projects.

As discussed here and in Sections 4.2 and 7, cost sharing is needed, and it should be done in a way that makes transmission costs appear to have a structure that is more compatible with a competitive market from the commercial market's point of view. This means eliminating the returns to scale, or equivalently, eliminating the fixed-cost component. As pointed out, there are other ways to cost share. It is important for the Board to resolve this issue by adopting a policy on cost sharing between reliability and commercial upgrades. Without such a policy, planning generation investments will be more difficult and Alberta's electricity market will be viewed as more risky.

6.4. Payment for Commercial Upgrades

Payment for commercial upgrades should not be made per-megawatt-hour of power transmitted. Purchasing a line is like purchasing a piece of capital equipment. There is a one-time (over-night) cost, and the purchaser is responsible for that cost regardless of use. That cost may be paid on an installment plan, or paid all at once but financed.

There are two reasons for this standard arrangement. First, pay-per-use puts the builder at risk and requires elaborate forecasts of future commercial developments. It would put the TA back in the central planner role. Second, if the purchaser paid per MWh of use, this would send the wrong signal for the use of the line, inappropriately discouraging usage. This would make the dispatch inefficient.

7. Overview and Conclusion

Investment in generation, investment in transmission, and the dispatch should each be guided by locational price signals. But the signals to generators depend on where the wires are and the signals for wire upgrades depend on where the generators are. In this circular system, where do the signals originate? How can they be made to work consistently?

The complete answer is not known, but some important relationships are well established and should be utilized. First, consider three possible rules for the supply of transmission capacity:

1. The absolutely-right transmission system could be built by an omniscient TA. (**Absolutely-right** transmission.)[8]
2. The TA could build transmission for all in-merit generation no matter where it locates. (**Gold-plated** transmission.)
3. Transmission could be supplied by a perfectly competitive market for wires. Cost could be constant per MW of capacity on a given path no matter how much or how little is purchased. (**Perfectly-competitive** transmission.)

Absolutely-right transmission and perfectly-competitive transmission are impossible. True gold-plated transmission appears so wrong in some situations that corners are always cut. So none of these is a realistic procedure, but they are all instructive to consider.

Energy prices can be set **uniformly** (with a few exceptions for transmission must run) as in Alberta or as competitive **locational** prices. Transmission rights can either **not** be provided, or a complete set of **tradable** rights can be provided and a perfectly competitive market for them established.

Consider the consequences of combining these possibilities into various market designs.

Design	Transmission Investment Rule	Real-time Energy Pricing	Tradable Rights		Outcome: Transmission Investment	Incentives for Efficient: Generation Location	Incentives for Efficient: Dispatch
1.	Absolutely-right	Locational	None	→	Perfect	Optimal	Optimal
2.	Absolutely-right	Uniform	None	→	Perfect	None	Poor
3.	Gold-Plated	Locational	None	→	Overbuilt	None	Optimal
4.	Gold-Plated	Uniform	None	→	Overbuilt	None (2 reasons)	Optimal
5.	Perfectly-Comp.	Uniform	None	→	None	Too strong	Poor
6.	Perfectly-Comp.	Locational	None	→	None	Too strong	Optimal
7.	Perfectly-Comp.	Locational	Transmission	→	Optimal	Optimal	Optimal
8.	Perfectly-Comp.	Uniform	Injection & Transmission	→	Optimal	Optimal	Optimal

Design 1 is the most ideal. Suppose the TA could figure out exactly where generators should locate and built the optimal lines for this optimal set of generators. Because lines are expensive, it would not eliminate congestion; it would build for optimal congestion (>0). Suppose the market used competitive locational pricing. Because of the congestion, energy prices would send locational signals to generators. These would be exactly the right signals and no others would be needed. (If two few generators located at C, then the price would go up at C and they would be attracted back.)

[8] The concept of "absolutely right" is subtler than it may appear. Transmission must be right for the optimal set of generators, not for the actual set of generators. But if it is right for the optimal set, then the intelligent investors would build the optimal set of generators. However, if lines are built to be optimal for whatever generators get built, the wrong set will be built.

Design 4 describes Alberta's market in 1999. At that time, there was little pressure for commercial expansion of transmission, but reliability was being threatened. With the gold-plating philosophy and without real-time locational energy price, there were no locational signals for generation investment. Without such signals, the TA would have been compelled to embark on an expensive upgrade of the N-S corridor. Instead, it correctly calculated that reliability could be more cheaply achieved by incenting generation investment in the Calgary area and proposed SERP. Unfortunately, SERP miscalculated the incentives, and because it used taxation as a signal, its mistakes would have been hidden from public view. (Its tax revenues were counted as a plus, but the higher prices, caused both by taxing generators and by higher production costs, were ignored.)

> LBCs send centrally planned locational signals. This makes sense for reliability projects.

The LBOC and LBC SO auctions provide the locational signals SERP was intended to provide and their relative transparency keeps them within reasonable bounds. Compare this with Design 1. In that design, the transmission system and energy market send energy price signals that give generation investors the perfect locational signal. The gold-plating/LBC design reverses the flow of signals. Locational signals generated by the TA, not by the market, are sent to generators. Generators locate better, and their location sends the TA a signal that less gold plating is needed on the transmission system. LBC auctions are an essential improvement for a system with no locational signals, but the overall design is a clumsy one.

> Centrally planned LBCs do not make sense for commercial projects.

Now we have Design 4 with LBCs. This system is not prone to overbuilding transmission for reliability. However, there are strong new commercial forces at work, which if left unbalanced, will lead to overbuilding just as reliability would have without LBCs. Because the TA derives the locational signals for the LBC approach from reliability calculations, LBC auctions do not handle the problem of commercial upgrades. The TA is quite right in not wanting to extend its calculations into this territory, as it is ill equipped to make the requisite profitability calculations. However, the solution of simply building all lines that could possibly prove profitable is as wrong as building all lines that could possibly be needed for reliability (without LBCs). Just as a trade-off is needed between reliability upgrades and generator location, so a trade-off is needed between commercial upgrades and generator location. The problem is that the TA has no way of calculating the right LBCs for this commercial trade-off.

Since Design 1 is impossible, the only reasonable path is to approximate a competitive market in transmission, Design 8. This might be avoided if building every possible commercial line resulted in only a modest over-building of transmission. Given the magnitude of transmission upgrades and generation investments under consideration, the results of gold-plating could be quite costly. Of course, the resulting excess of transmission would be partly concealed by the mislocation of generation that it would induce.

> A market approach with tradable rights is required to give correct locational signals for commercial projects.

A perfectly competitive transmission market is not possible because of the returns to scale in the provision of transmission. But, allowing commercial upgrades to piggyback on reliability upgrades and allowing the TA to build economically sized lines and sell them at average cost can make transmission costs appear more linear. This will improve the functioning of the transmission market.

The market approach to commercial upgrades, as explained above, requires the introduction of tradable rights. These, in effect, introduce some locational energy pricing on the generation side of the market. There is simply no way around this if market signals are to be used to help locate generation and site transmission. This approach is not perfect and if the essential structure of the transmission system becomes too complex, it may be necessary to resort to explicit locational energy prices and financial transmission rights. Even this would not provide a perfect market for transmission upgrades, but it might be needed in a more complex network. The problem of transmission's returns to scale would remain, and this would still prevent perfect competition.

Given present constraints on market design and the magnitude of the transmission questions that must be decided in the near future, the proposed market approach, imperfect though it is, provides the best alternative. It harnesses the most well informed sources and gives them reasonably accurate incentives. Most importantly, as with the replacement of SERP by LBCs, it provides substantial protection against the most dangerous potential outcomes.