Transmission Tariffs by Use of System and Economic Benefits

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Abstract

Setting electric transmission tariffs is a classical multi-objective problem. The tariff problem is particularly challenging in modern power markets where transmission has been separated from generation and distribution. This paper shows how the transmission tariff problem should be formulated. The principles – and their application in reality – are illustrated by the recent development of new transmission tariffs for Peru, for which the authors were responsible. The cost allocation in Peru was based on economic benefits and use of system. This paper shows how setting tariffs is an interplay between fundamental principles and practicalities, including local law and circumstances. Tariff factors are identified that that could impede development of the transmission system by creating unnecessary business risks and that can create serious inequities.

1. Introduction

Our concern is for transmission systems that are treated more or less as protected monopolies, though they may exist within competitive power markets. There are variations within this general model, but it is common. In this model, transmission tariffs are set to recover certain fixed and operating costs, sometimes called "revenue requirements."

We are concerned with how the revenue requirements are allocated, not with how they are computed. We note that most of transmission revenue requirements are fixed capital-related costs – variable operating costs are low. There are several bases for the capital costs:

- Embedded historical costs,
- Replacement costs, and
- Cost of an "optimal" benchmark system.

Our allocation problem is indifferent as to how the revenue requirements are calculated.

Alfred E. Kahn said, "The central policy prescription of microeconomics is the equation of price and marginal costs. If economic theory is to have any relevance to public utility pricing, that is the point at which the inquiry must begin" [1].

However, Kahn hastens to add that practical issues require significant adjustments to simple application of marginal-cost pricing. In particular, marginal-cost rates for transmission services usually significantly under-recover revenue requirements and hence are not sustainable. A revenue reconciliation adjustment must be made to recover the capital and operating expenses. This adjustment may be considerably greater than the marginal cost [2]. Accordingly, what starts out as a marginal-cost rate ends up an allocation of revenue requirements.

A recent paper discusses further the challenges of reconciling practical and theoretical issues [3]. Another analyzes issues associated with pricing use of a single transmission asset, as is done in Peru [4].

We will discuss and illustrate this and other elements of the practical adjustments to pure economic and physical theory.

There are three fundamental approaches to allocation of transmission revenue requirements:

1. By economic benefit or marginal cost,
2. By use (MW-mile methods), and
3. By socializing (postage stamp).

All are valid; all exist in many variations [5], [6]. Our discussion will be illustrated by new tariffs for Peru, which include elements of all three.

2. Tariff objectives

2.1. Transmission Tariff Objectives

The most important step in transmission tariff design is to identify the objectives of the transmission tariff. The transmission tariff the authors recently designed for Peru attempted to meet the following objectives.

1. Be fair and be viewed as fair.

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2. Recover all revenue requirements.
3. Send correct economic signals.
4. Be predictable and stable.
5. Be consistent with the law.
6. Be transparent and understandable.
7. Be practical, not forced by abstract economic theories.
8. Be reasonable, not requiring complex computations.
9. Be consistent with physical realities.
10. Minimize the number of tariff methods in use. In particular, use the same methods for similar classes of transmission assets.
11. Minimize the changes from existing tariffs.

Some of these objectives (for instance, (2) and (5)) were absolute requirements. For practical reasons, (10) and (11), which were related to (1), (4), and (6), weighted heavily in the final determinations.

These eleven objectives conflicted with each other. For instance, if taken as absolute, #11 would mean, "Change nothing," and #4 would freeze tariffs forever.

2.2. Comparison to other approaches

It is reasonable to ask how the authors' approach – beginning with definition of objectives and proceeding to development of a tariff – compares with other approaches, e.g., traditional integrated resource planning, the current US mix of regulated investment and market-based tariffs for merchant transmission investment, and the "participant funding" approach used in Argentina. Our work was motivated by a problem in Peru.

This paper is not about planning, but integrated planning shares with the authors' approach the recognition that power systems impose a variety of costs on society, not all of which can be expressed in monetary terms. Formal methods have been developed to resolve these costs. The authors are very familiar with these methods. As will be discussed below, we found that resolving conflicts in an *ad hoc* manner was reasonable for this problem.

As in parts of the US, in Peru responsibility for transmission planning and ownership is divorced from generation ownership. The tariff problem in both countries addresses similar problems: whether transmission is to be a cost-recovery business and how to make it so, how to allocate cost responsibility, how to cover risks, etc. The laws and conditions in the two countries require slightly different approaches. Our method strives to recognize tariff objectives explicitly.

In Peru, all lines are "merchant" in ownership but with cost recovery guaranteed either through tariffs or bilateral contracts. These bilateral contracts, entered into by generation or major loads, allow generation or load to participate in funding transmission. We do not discuss this issue, but note that Peru has rules and tariffs for use of such transmission by other parties.

2.3. Allocation to Services

Many countries have markets for various transmission and ancillary services, such as use of system, uplift, losses, balancing, etc. Allocation of costs among these services, and to the generators or demand for these services, is beyond the scope of this paper. Nonetheless, the principles and objectives above are applicable to the allocation of costs associated with these services.

3. Practical case: Peru

The principals and methods described in this paper are illustrated in the recent development of new tariffs for the transmission system of Peru. Here we provide the context.

3.1. The Peruvian power system

Peru is about 2,000 km from north to south and is about a fourth as wide in the east-west direction.

Peak demand in 2007 was about 3,966 MW. Energy consumption was about 27,254 GWh.

As of 2007, Peru had about 400 generators, 61% participating in the market and 39% self-generators. In terms of capacity, 6,020 MW of generation (85%) participate in the market while 1,038 MW (15%) is self-generation. Some 5,800 MW (53% hydro, 47% thermal) are part of the interconnected system. The balance serve isolated system load. The hydro plants tend to have limited storage, so their production is heavily dependent on mid-term and short-term fluctuations in rainfall.

Just under half of Peru's electric energy is consumed by large industrial clients, mainly associated with mining, served under bi-lateral contracts or self generating. Regulated customers pay an average of US$0.089/kWh.

The interconnected system has two major zones, connected by a weak double-circuit 220-kV line. The system has about 9,050 km of 220-kV and 138-kV transmission lines. Except in the Lima area, the transmission system is generally radial.

3.2. The Peruvian power market

Peru has fifteen generating companies, of which three are dominant. It has more than fifteen distribution companies, or energy service providers, two of which are dominant. It has six transmission companies, one of which is much larger than the others.

Generation is competitive and generation planning is left to the market. Generation dispatch is based on costs, not offered prices. The production scheduling and dispatch is computed by a hydro-thermal production simulation program that recognizes transmission constraints.

Wholesale prices for electricity are based on short-run marginal costs, computed a year in advance using the hydro-thermal production simulation program mentioned above. Retail prices include wholesale prices and distribution system costs.

Transmission planning is centralized. Some planned projects are offered for bid, the successful bidders receiving regulated return on investment and return of investment and operating costs.

Some transmission projects, planned or not, are built under bilateral contracts between transmission providers and generators or large users. Rates for these are not regulated. Most of these projects are radial.

3.3 Transmission Tariff Law

Law 28832, "To Assure the Efficient Development of Electric Generation," was passed in 2006. It significantly updated the earlier 1992 law. Key elements regarding transmission tariffs include:

1. Allocation of responsibility for revenue requirements between generation and load is fixed forever when the project is built.
2. This allocation was to be based on projected economic benefits for trunk facilities when we did our work. Since then, Law 28832 was changed to assign the total cost of new trunk facilities to load. The allocation between load and generation *may* be based on economic benefits or use of system for other facilities.
3. Revenue requirements assigned to load are postage-stamped to a local area or throughout the interconnected system.
4. Revenue requirements assigned to generation for new transmission projects may be allocated based on economic benefits or use of system.
5. Existing facilities are grandfathered insofar as whether tariffs are computed based on economic benefits or use of system.
6. Benefits due to increases of reliability should be considered.

3.4. The need for new tariffs

Several issues were recognized as requiring new transmission tariffs.

The 2006 law required that the use-of-system method recognize bi-directional flows. The existing method did not do so.

The existing economic benefits method, based on locational marginal costs, gave very unstable results.

The existing methods did not recognize changes in reliability in assigning cost responsibility for projects.

There were two important unrecognized issues. First, the tariff structure did not deal well with certain risks. Second, marginal-cost based electricity tariffs were shown to be impractical when congestion occurred in 2007 and were suspended by presidential decree. Perceived economic benefits of new transmission were distorted by marginal-cost issues when congestion occurred.

3.5. Allocation between load and generation

Significant differences between generation and load make it hard to allocate revenue requirements between them. It can be argued that:

- Reliability benefits are more important to load than to generation. Therefore the load should pay all or the lion's share of transmission enhancements that affect reliability. This includes transmission reinforcements needed to meet planning criteria.

- Every kWh that passes through the transmission system originates in a power plant and is absorbed by a customer. Therefore the generation and the load use the transmission system equally, and the cost should be shared 50/50.

- Only the load injects net money into the power system. Generation, transmission, and distribution systems all exist to provide service to the customer. Though they invest in facilities and incur operating costs, they recover these investments and costs and make a profit, taking net money out of the system.

By this last theory, allocating part of transmission revenue requirements to generators is futile – in one way or another the generators will pass these costs to the ratepayer. Therefore all costs of transmission should be allocated to the ratepayer directly, eliminating passing transmission costs through a middle-man, the generator.

This theory has practical exceptions regarding interconnection costs that are assigned to a power plant. Controls are needed to prevent power plants locating irresponsibly and expecting ratepayers to pay for unreasonable transmission.

None of these positions can be proven "right" from first principles. The choice reflects taste and the objectives discussed above. The authors confess a preference for the third argument, but reserve the right to change their minds.

Within the US PJM system, which covers all or parts of 13 eastern states and the District of Columbia, transmission costs (except generation interconnection costs) are allocated to the ratepayer. Generators wanting to transmit power through PJM, and generators using other US systems, pay transmission tariffs. These are in effect credited to the ratepayers, reducing what they would otherwise have paid.

In traditional vertically-integrated utilities, all transmission costs are allocated to the ratepayer. The transmission system may be used by outside parties, for instance for wheeling. When charges are levied for this service, they are credited to the ratepayer immediately or in the next rate case.

Table 1 summarizes the allocation of transmission costs to generation and load in 23 European countries [7]. This large table makes graphically clear that there is no consensus in Europe on allocating transmission costs between load and generation. However, the allocation generally assigns more responsibility to the load.

Table 1. Allocation of transmission costs in Europe, 2006

	Generation	Load
Austria	16.5%	83.5%
Belgium	0%	100%
Czech Republic	0%	100%
Denmark	2-5%	95-98%
Estonia	0%	100%
Finland	12%	88%
France	2%	98%
Germany	0%	100%
Great Britain	27-50%	50-73%
Greece	0-15%	85-100%
Hungary	0%	100%
Lithuania	0%	100%
Ireland	20%	80%
Italy	8%	92%
Netherlands	0%	100%
Norway	35%	65%
Poland	0.04%	99.6%
Portugal	0%	100%
Spain	0%	100%
Sweden	25%	75%

4. Quantifying economic benefits

4.1 Benefits in a marginal-cost market

In a marginal-cost market, ratepayer economic benefits of a transmission project are the difference between electric bills (excluding transmission charges) with and without the project. Generator economic benefits are the difference between net income (revenues minus operating expenses) with and without the project.

When there is no congestion without the project, these economic differences are driven by changes in I^2R losses and are minor. In fact, they are small differences between large numbers. This means that they are affected by the numerical precision of the large numbers and are therefore unstable.

Where there is congestion, instability in computed economic benefits occurs for different reasons. Marginal costs are based on derivatives (in the calculus sense) of production cost. Taking a derivative tends to amplify noise. Variations in marginal cost due to variations in demand, fuel prices, hydrology, etc., can significantly affect marginal costs, dispatches, congestion – and perceived economic benefits. See Figure 1.

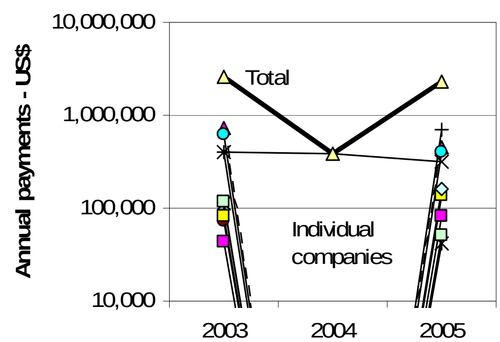

Figure 1. Revenue requirements for one line, assigned to various generation companies in Peru, based on yearly economic benefits. Note that total revenue requirements changed by almost an order of magnitude, for reasons not germane to this paper, while for some companies assigned revenue requirements changed by much more than that.

4.2. Congestion costs and excess payments

Tariffs of any kind based on marginal costs have a fundamental defect: the books do not balance when there is congestion. In particular, the aggregate payments by the load exceed the payments to the generation when there is congestion. This creates significant distortions.

For instance, Table 2 shows the economic effects of a new 500-kV line that will relieve west-to-east congestion in PJM [8].

Table 2. Economic effects of a new line in PJM in a test year, millions of US dollars.

Change in Production Cost	-140
Change in Gross Load Payment	-621
Change in “Congestion Costs” (rebates to consumers via Financial Transmission Rights, or FTRs, which in PJM are essentially allocated to consumers)	-790
Change in Generator Revenues (Net Load Payments)	+169

In Table 2, by reducing congestion the new line would reduce production costs by $140 million. The gross load payments (locational marginal cost x kWh consumed) would go down by much more, $621 million. But the “congestion costs” rebated to the load would decline even more – by $790 million. This means that the relief of congestion would actually make net payments by load – gross payments minus congestion cost rebates – increase by $169 million. This $169 million is also the amount by which generator revenues would increase with the reduction in congestion.

The mechanics of this process can be made clearer by considering two areas connected by a single line. See Figure 2.

Without the new line (top of Figure 2) the ample cheap generation to the left (area A) cannot satisfy all of the market to the right. The marginal cost at the right ($50/MWh) is set by a small expensive generator in area B. The load at the right pays for all 100 MWh of its electricity at this marginal rate – a total of $5,000. But the generator at the right is paid $1,500 (30 MWh x $50) and the generator at the left is paid $350 for the 70 MWh he supplies. The load pays more than twice what the two generators receive.

In PJM, these excess payments ($3,150 in Figure 2) are called “congestion costs” – a name that has caused confusion. They are really “excess payments under congestion in a marginal-cost pricing system.”

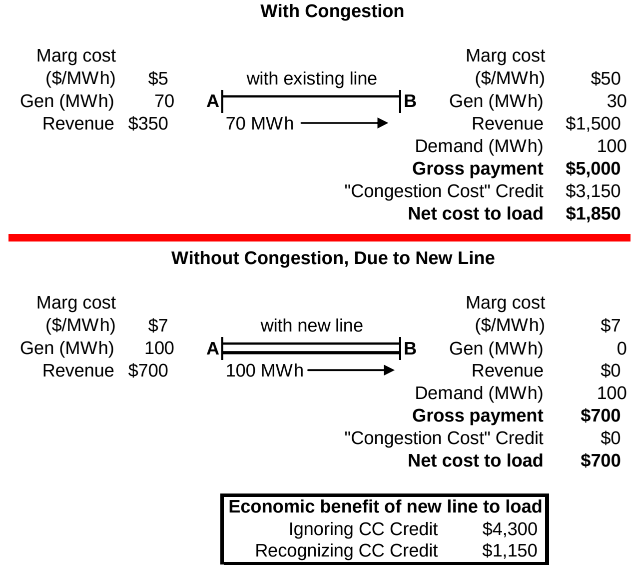

Figure 2. The effects of congestion on gross and net consumer payments and on apparent and real economic benefit of a new line.

The increase in system production cost due to congestion is the difference between generation or production cost with and without the congestion – the top and bottom of Figure 2 - $1,850 minus $700 – or $1,150.

In PJM, the “congestion costs” at the top of Figure 2 – $3,150 – are rebated to the ratepayer through a complex “hedging” mechanism involving financial transmission rights (FTRs). This attempts to return the “congestion costs” to those ratepayers who paid them.

(It has been observed that in PJM the FTRs, which were originally allocated to the ratepayers through load serving entities (LSEs), may have been sold by the LSEs. The purpose of the FTRs was to hedge ratepayer congestion risks. The LSEs choose for the ratepayer whether to retain the FTRs, in case of possible congestion, or to sell them for sure cash. Whether they are sold or not is irrelevant to our argument. Presumably the expected value of the FTRs, if retained by the LSEs, bears some relation to the market price for FTRs.)

The true net costs of congestion to the ratepayer – the $1,150 of the previous paragraph – are called “unhedged congestion costs” in PJM.

Peru also has a mechanism for returning “congestion costs” to the ratepayer. Its mechanism, too, is complex, and the details are not important for this paper. But the Peruvian mechanism in essence returns the “congestion costs” to the ratepayers as a whole, as a per-MWh credit against transmission charges – not to those who, as at the right of Figure 2, made the “excess payments under congestion.”

As a result, when congestion became significant in Peru in 2007, the ratepayers in the constrained area saw a significant increase in bills, without the hedging relief of the “congestion cost” credit, which was spread throughout the country. This increase was so big that the President of Peru suspended marginal-cost tariffs by emergency decree [9].

4.3. Benefits and Excess Payments

The computation of the economic benefits of a line must recognized that the so-called “congestion costs” are really a refund to the ratepayer, not a cost to the ratepayer. Otherwise, the perceived economic benefit to the ratepayer of a line that relieves congestion can be greatly exaggerated.

In the example of Fig. 2, without recognizing the return of “congestion costs” to the ratepayer, the new line at the bottom of the figure reduces the gross payments from the consumer from $5,000 to $700 – a perceived benefit of $4,300. But if the “congestion costs” are recognized as being returned to the ratepayer, his net payments will decline from $1,850 to $700. The true economic benefit of the line to the ratepayer will be only $1,150.

If responsibility for paying the revenue requirements is assigned based on economic benefits, this difference in perceived benefits of nearly 300% will have a significant effect on transmission tariffs.

5. Quantifying reliability benefits

The wording in the 2006 law in Peru is wise. The legislators did not insist that the monetary value of reliability benefits be computed and added to the economic benefits of a line. Rather, the law says that “those who benefit from increased reliability will be recognized.”

This is important because we do not have models which can with confidence tell us how a new transmission line will reduce lost consumer load, as measured by such indices as SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency index).

We also do not have models which can tell us with confidence the dollar value to the consumer of a change in these indices.

We recognize that efforts have been made to estimate reliability costs to consumers. For the reasons given above, the authors were not comfortable in enshrining these estimates in a tariff procedure on a par with the capital-related costs of transmission and the costs due to congestion, which are computable with fair precision.

Accordingly, for the Peru problem, the authors assign all of the revenue requirements on the basis of economic benefits if the economic benefits of a line exceed 90% of the revenue requirements.

If the economic benefits of line are less than 10% of the revenue requirements, we presume that the line was built for reliability purposes. The revenue requirements are shared on a per-MWh basis by all generation and load upstream of the line.

(This assumes that the preponderant part of the system, which we define to be “downstream” of the existing line, is big enough that it will not suffer a blackout if the line is lost, hence a new line will not increase its reliability. The small portion of the system upstream of the line is presumed to be more vulnerable to failure – tripping of load and generation – if the line is lost. If the new line is enmeshed in the middle of the system, and not identifiably benefiting any subsystem, then the payments for reliability benefits are spread over all load and generation on a per-MWh basis.)

In the intermediate case, where economic benefits are between 10% and 90% of the revenue requirements, the revenue requirements are assigned partially on the basis of economic benefits, and partially per MWh of generation and load upstream of the line.

6. Quantifying use of system

6.1. Transportation versus transmission

Two classes of ways to quantify use of system are based on radically different network models.

One approach is to treat the transmission system as a transportation system – a gas pipeline or a system of roads and trucks – where something enters the system at one point and s transported to another.

In our view, a force-at-a-distance model – like the lever of Fig. 3 – is more consistent with the laws of electricity and with attributes of power transmission. For instance, in a force-at-a-distance model no thing flows along the lever – not even electrons travel from a power plant to a customer – in alternating current systems the electrons just jiggle back and forth and in direct current systems they make a round trip.

In electric transmission systems, an unloaded line can be of critical importance, while an empty truck is useless. In electric power transmission, the system as a whole permits transfer of energy.

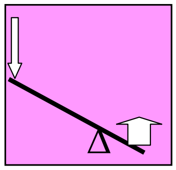

Figure 3. The transmission network is more like a lever than like a transportation system.

6.1. Transportation Models of Use of System

There are many of these models. They all attempt to measure the flow on the various transmission lines due to a particular transaction or power plant or load. The fraction of the capacity of the line – or maybe of its loading – due to the transaction determines the share of the cost of the line to be assigned to the transaction.

Peru has used one such method to measure use of system [10]. Figure 4 illustrates it.

The method traces the net flows through the system – for example, it assumes that 100% of the power on the three lines exiting bus 1 is from the 400-MW generator. "[The] zero share of generator G2 in the flow in line 1-3 is quite obvious (G2 cannot possibly supply this line)" [10].

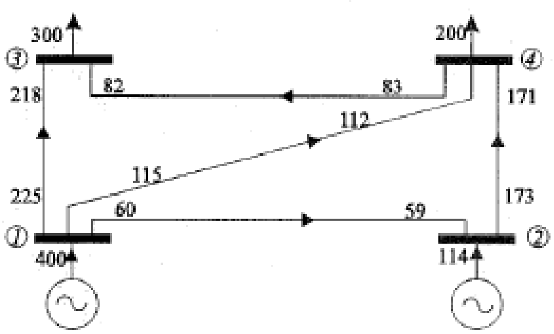

Figure 4. Net flows are used to measure use of system in a transportation model.

This seems incorrect. The net flows on the network are the sums of the flows from the individual generators, by the superposition theorem. Kirchhoff's laws say that the individual flows are independent of each other. In any given moment the net flows are the sums of the flows from the various generators to the various loads.

Peru's application of this method, or of something like it, was mandated by the 1992 law, which required allocation on the basis of net or preponderant flow.

The method has practical problems. Peru applies it in real time, sending flow and injection measurements integrated over fifteen minute intervals to the control center to compute billing for use of part of the system. This amounts to 35,000 numbers per measured point per year – a data nightmare that cannot be ignored by saying, "We'll just dedicate a PC to the task." For one thing, keeping the data synchronized is impractical, and asynchronous data gives erroneous results.

In addition, the flows can reverse. Suppose a line has 100 MW flowing to the north for 5 minutes, followed by 100 MW to the south for 10 minutes. The 15-minute integral would be to the south, with the south-bound transaction having 100% of the responsibility for the revenue requirements. If the flows were integrated over five-minute periods the north-bound transactions would bear 1/3 of the cost responsibility. So the arbitrary assumption of integration period would determine the cost responsibility.

The 2006 law required use of system computations to recognize bi-directional flows, which this method is incapable of doing.

6.2. Force-at-a-distance models of use of system

Force-at-a-distance (MW mile) models work better and are simpler. The force can be measured in GWh generated or consumed per year or in annual peak MW of the generator or load. Using energy (GWh) is generally preferred, as the annual peak is more variable, depending on weather conditions during a single hour.

These models can use electrical distance or physical distance. Both are relatively easy to compute. The electrical distance from every bus j to bus i is the impedance z_{ij} between the two buses. This is a column of the $\mathbf{Z}_{bus}$ matrix, the inverse of the $\mathbf{Y}_{bus}$ matrix, with bus i taken as the reference bus [11].

Geographic distance, straight-line or otherwise, can also be used. If a system is designed according to uniform criteria throughout, geographic and electrical distances are correlated.

The authors prefer using electrical distance, as this avoids certain untidiness in computing geographic distances. This also reflects network changes: as new lines are added, electrical distances are reduced, while geographic distances do not change.

The costs of the system as a whole may be allocated. The allocation should recognize that the more distant loads or generation generally "use" more of the system, and the costs can reasonably be allocated in proportion to $GWh_i \times d_i$. The distance d_i, whether geographic or electrical, is a weighted average distance from bus i to all load buses, if bus i is a generation bus, or to all generation buses, if bus i is a load bus [12].

In Peru, the costs of individual elements (e.g., lines) are allocated, one by one. This allocation should recognize that remote loads or generation generally "use" a line less than do nearby loads or generation, and the allocation can reasonably be proportional to GWh_i / d_{ij}. Here d_{ij} is the distance from bus i to element j. For convenience, we take the distance to the midpoint of element j.

Figure 5 shows the transmission charges for various power plants for use of part of the EHV system near Lima, based on GHW/ohms. Two things are striking.

First, the method reasonably charges much more per GWh generated to the nearby plants, which presumably use the Lima system more than do the remote plants, much of whose energy can be thought to feed local loads.

Second, the per-GWh charges are quite invariant from year to year. The generating companies are not subject to surprising swings in their transmission bills.

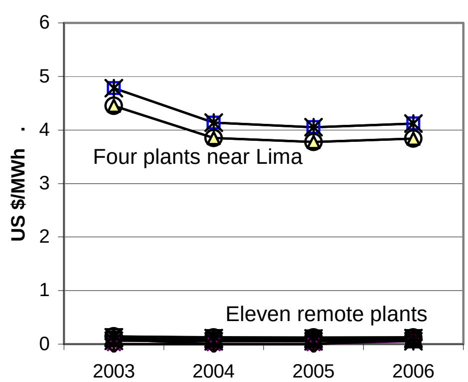

Figure 5. Per MWh charges to generator for use of transmission system near Lima, based on GWH/ohm.

We note without apology that the choice of a method to measure use of system for cost allocation is arbitrary. There is no theoretically "right" method. We have described several methods. Our choice for application in Peru was based on the reasonability arguments given and on the criteria listed above.

7. Risks

7.1. Random fluctuations due to marginal costs

The locational marginal costs of power are random variables. This is because the load, hydrology, and availability of individual power plants are random. In a system like Peru's, with significant hydro resources, the randomness in locational marginal costs is amplified. The only true dollar costs of production are associated with the thermal plants. The "costs" of the hydro plants are shadow prices derived from thermal costs as a by-product of an energy optimization process, which introduces another element of variability.

As a result, the computed marginal-cost benefit of a new element, which is the difference in marginal costs at the two ends of the line, can fluctuate significantly. If payments to transmission owners are based on these benefits, they also can fluctuate significantly. See Figure xxx. This makes transmission owners subject to an unpleasant level of cost-recovery risk. If not mitigated, this creates a real cost which, in one way or another, will be covered by the ratepayer, the only party who injects net money into the system.

One way to solve this is by passing the (monthly) raw economic benefits through a digital filter to damp the swings.

7.2. Delay or loss of line

If a new network element is delayed, or if an existing one goes out of service temporarily or permanently, for example, due to an earthquake, who pays for it? This risk cannot be absorbed by the transmission company. It doesn't have the internal resources to self-insure, and commercial insurance to cover such an event, if available, would be expensive.

Under the traditional regulatory contract, these risks are absorbed by the consumer. The element is put in the rate base, where it remains until the capital investment is recovered, even if it goes out of service prematurely. A large customer base spreads out and therefore can absorb the risks associated with individual elements.

In Peru, the law makes it difficult to cover this risk. The allocation of cost recovery between demand and generation is done once, permanently, when the element enters service. If the allocation within the generation group is by use, and if the element is not in use, then there is no one to pay for it.

7.3. Loss of generation or load

A similar problem is associated with loss of a significant generator or load, for example, through economic or natural events, for whose benefit a line was built.

For instance, suppose that a line was built to serve a large mine, and incidentally a small village nearby. If the line's costs were allocated to demand – the mine and the village – and if the mine shut down, then the village would be responsible for all of the costs of the line. This risk cannot be born by the village or by the transmission owner, for practical reasons discussed above. By law, it cannot be passed along to ratepayers nationally.

7.4. Responsibility for excess capacity

Some major transmission additions are lumpy. This implies that when additions are made, the system appears over-designed until load growth catches up.

If the benefit or use of the system is local, it may be burdensome to recover the costs of the excess capacity locally.

These costs can be capitalized and recovered when the element is more heavily loaded, or they can be spread over the total system. Neither approach appears legal under current law in Peru.

7.5. System evolution

Under Peruvian law, the allocation of responsibility between load and generation for a transmission element is fixed once, when the element goes into service. If over the 30- or 40-year lifetime of the element the system evolves so that the element benefits or is used differently, there is no formal provision for revisiting the initial allocation. Either such a provision should be made, or cost responsibility for each element should be allocated throughout the system.

8. Conclusions

8.1. Transmission tariffs in Peru

We began by presenting eleven objectives to guide the development of new Peruvian tariffs. These objectives are referred to by (number) below. These objectives both conflict and overlap. The authors have extensive experience with formal methods for resolving conflicting objectives. For this application, these methods were not needed.

It became clear that meeting two of the objectives, (10) minimizing the number of tariff methods and (11) minimizing the changes from existing tariffs, would be extremely important in achieving acceptance of the new tariffs.

To meet these objectives we developed tariff allocations based generally on economic benefits. In limited circumstances where this could not be done because of (5) grandfathering rules or because (7, 8) economic benefits could not be computed, we developed tariff allocations based on use of system.

In order to (5) be consistent with the new law, we modified the economic benefits allocation to recognize benefits (though not quantified) of increased reliability.

In order to (5) be consistent with the new law, (8) avoid having to make computations based on real-time data sampled every 15 minutes throughout the system, and (9) be consistent with the laws of physics, we replaced the previous method for computing use of transmission elements with a force-at-a-distance GWh/ohms system.

In all cases, we trued up monthly transmission revenue collections at the end of the year (2) to recover all revenue requirements.

We provided a digital filter (4) to reduce the month-to-month and year-to-year billing fluctuations seen by the generators. The new use of transmission method also reduced these fluctuations.

We identified a significant problem with regard to congestion-related costs. We incorporated a fix (1, 3) in the interests of fairness. We trust that this fix will be found to be legal.

Although (3, 7) pure economic theory has long since been left behind, and in any event cannot be applied without major adjustments, we believe that the final result sends reasonable albeit imperfect economic signals.

The resulting tariffs are more than 100 pages long and are not light reading. We seem to have failed with regard to (6) transparency. However, with the exception of the bus marginal cost calculations, (8) the computations are readily understandable and are not burdensome.

We trust that the results (1) will be fair and will be perceived as fair. This objective was fundamental.

Certain constraints imposed by Peruvian law need to be addressed, particularly regarding risks and system evolution.

8.2. General conclusions

We have presented two bases for allocating the responsibility for cost recovery of transmission elements, according to economic benefits and according to use.

The first has an impeccable economic foundation, though practical issues require enough adjustments to make its foundation almost unrecognizable. The second is fundamentally arbitrary, based on common sense and reasonability arguments.

Tariff design, in either case, must begin with careful identification of objectives.

We illustrated these principles by reporting a redesign of Peru's transmission tariffs. We first developed a list of tariff objectives. As the tariff revision proceeded, the relative importance of these objectives was revealed. The resultant tariff (which as of this writing is still in draft form, awaiting regulatory approval) respects some of these as absolute constraints and strives to achieve others.

We conclude that setting tariffs, though it must be based on sound economics and physics, is importantly an exercise in reasonability, constrained and colored by law and local circumstances.

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