PRIVATE INVESTMENT IN TRANSMISSION

FOUR BUSINESS MODELS FOR EMERGING MARKETS

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Four Business Models to Facilitate Private Investment in Transmission

There is currently a need for significant additional investment in transmission in emerging markets. This need is unlikely to be met through the existing sources of funding for the sector.

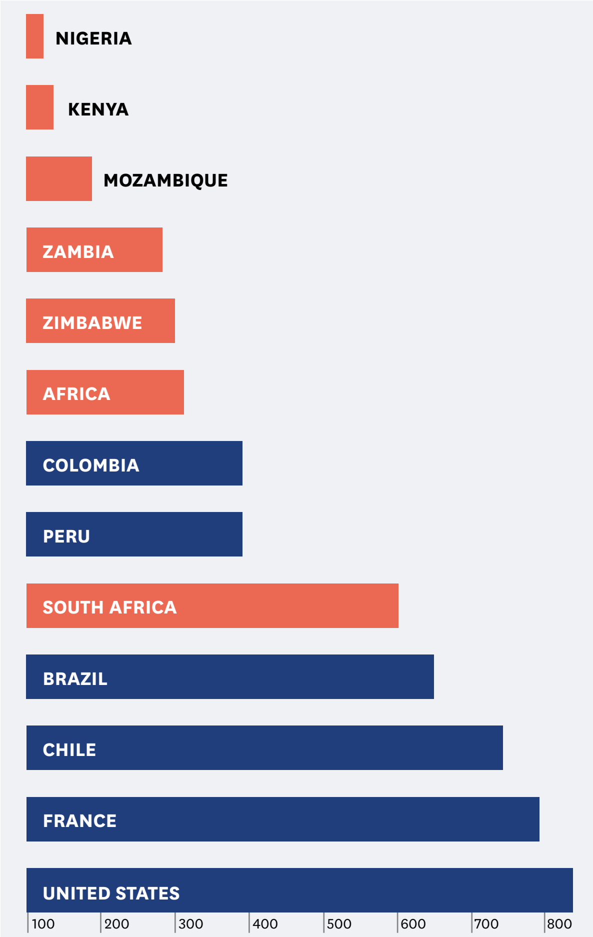
In emerging markets, investment in new power generation over the past few decades has not been matched with corresponding investment in electricity networks, and this is now a major constraint on increased access. As well as the energy access imperative for transmission investment, it is also critical to economic development. Numerous studies have demonstrated the economic value of increasing investment in electricity transmission systems.

Access to reliable and affordable power for businesses is critical for the industrialization of developing countries and suitable capacity on a well-maintained high voltage transmission backbone is a prerequisite to this that is missing in many countries.

Finally, transmission infrastructure is essential to support the transition towards energy systems that are less carbon intensive. Investment in grid stability is necessary to support an increased percentage of intermittent renewables in the generation mix, and a larger transmission network will be necessary in most countries to connect areas of high renewable generation potential with areas with demand. For example, the investments Egypt made between 2014 and 2020 illustrate the scale of the investments that could be required to integrate renewable energy resources. Between 2014 and 2020 the Egyptian Electricity Transmission Company commissioned over 3,600 km of 500 KV transmission lines. At the end of 2020, the length of their 500 KV transmission system was 2.5 times its length in 2014. Much of this investment was necessary to connect new renewable energy projects in the south to load centers in the north.

The International Energy Agency has estimated that achieving SEAsia's electrification ambitions will require "a major additional push to deploy a range of renewable technologies."[1]

Historically, the vast majority of investments in transmission on the continent have been made



Kilometers of transmission lines per million people

by state-owned utilities. For the most part, these investments have been funded by government, or with support from government through sovereign backed loans from multilateral development banks. This source of funding for the sector has not kept pace with the need for transmission infrastructure, and the bottleneck created by this represents a major economic development challenge and a climate problem. Without additional sources of funding for the sector, Sustainable Development Goal 7 (*access to affordable, reliable and sustainable energy for all*), and 2050 net zero climate commitments set by governments will not be met. Growing pressure on governments budgets, particularly in the wake of the Coronavirus pandemic, have compounded this problem as many nearer term projects that had been earmarked for government support have now stalled.

Until the 1990s, state-owned utilities were responsible for investments in transmission in most emerging markets. That decade saw a wave of restructuring across Latin America, along with many members of the OECD, which led to new business models for developing and financing transmission infrastructure.[2] At least one of these models—the independent transmission project model—was successful enough at decreasing costs and reducing project implementation risks that it has subsequently been employed in the US and the UK even though the transmission systems of both countries are, by and large, privately owned networks. In the UK, the Office of Gas and Electricity Markets (Ofgem) estimated that using that model resulted in cost reductions of between 23% and 34% in relation to approximately £3 billion of investment in transmission related to new offshore wind projects.[3] In the US, a recent report estimated that competitive transmission development processes can be expected to yield cost savings ranging from 20% to 30% on average, when compared to non-competitive development by incumbent transmission owners.

Investment in generation is usually considered to be easier to structure and organize than investment in transmission. Agreeing roles and responsibilities between a private investor and state-owned utility is more difficult with transmission assets which are often closely integrated with the existing network. Transmission networks are usually centrally planned and organized to a very high degree by the government or state-owned entities and it can feel like a loss of control to open up the network and involve third parties for the first time, particularly for governments, which still often consider transmission infrastructure as strategically significant. However, in the current fiscally constrained economic environment, it is clear that the governments in emerging markets that can unlock new sources of funding for the energy sector will be the governments most likely to succeed in expanding electricity access, improving the provision of power to industry and improving sector sustainability.

There are many transmission projects without funding at present which have the potential to build critical infrastructure with a clear accretive financial case. National development plans depend on this infrastructure being built, and the global energy transition relies on suitable network infrastructure existing in order to unlock renewable energy sources.

At least four different business models could be used to facilitate private investment in transmission infrastructure across emerging markets Those four business model are:

- whole of network concessions,
- independent transmission projects (ITPs), which are also known as independent power transmission projects,
- privatizations (a sale of shares by a government in a state-owned utility or transmission company), and
- merchant lines.

These four models are described, in the most general of terms, below. In subsequent articles, we will examine some of these models and the issues they present, in more detail. As is the case with independent power projects, and public-private partnerships more generally, these models are flexible and can be tailored to better address unique needs, constraints, and challenges. As a result, the models described below should be taken for that are—archetype-like models that can be modified so that they can be implemented across a wide variety of circumstances.

Whole of network concessions

In a typical whole of network concession, the owner of the transmission system grants a long-term concession over the existing transmission system, typically for 20 to 30 years. The private investor awarded the concession is then responsible for operating and maintaining the existing transmission network and for financing and constructing new investments in transmission infrastructure in the service territory over the term of the concession. This model has resulted in

significant investment by the private sector, significant loss reductions, and significant improvements in key performance indicators in some emerging markets. A few key challenges must be overcome before this model can be implemented successfully. These challenges are identified below.

1. Regulation

Network industries require significant levels of on-going investment. In addition, operations and maintenance costs are likely to vary significantly over the term of a typical concession as the network expands and connections to the network increase. As a result, it is not feasible for investors to bid an availability payment or use of system charge that will apply over the term of the concession. Instead, the business is regulated using cost of service or performance based ratemaking concepts. Both of these forms of regulation rely on periodic determinations of the regulated asset base (the quantum of investments made by a utility on which the utility earns a return and which are recovered by the utility by including a depreciation charge in the utility's annual revenue requirement), the cost of debt, the cost of equity, and the cost of operations and maintenance that should be recoverable by the utility.

As a general rule, investors and lenders are reluctant to rely on an independent regulator to establish rates based on cost of service or performance based ratemaking concepts unless the regulator has an established track record of fairly balancing the interests of consumers and investors. Few regulators in emerging markets have had an opportunity to establish such a track record. The fact that rates paid by consumers are not cost-reflective in the vast majority of emerging markets significantly heightens perceived risks regarding the stability of regulatory frameworks and the practical ability of regulators to balance the interests of consumers and investors.

2. End of term payments

Because network industries require significant levels of on-going investment, the investments made by the private sector will not have been fully depreciated by the end of the term of the concession, no matter how long the term.

As a result, the state-owned utility (or the host country) will need to make a sizeable payment to the concessionaire at the end of the term (a buy-out payment). A state-owned utility or host government could raise the capital required to make such a buy-out payment by entering into another concession at the expiration of the first concession and requiring the new concessionaire to pay an up-front concession fee that corresponds to the size of the buy-out payment owed to the first concessionaire. A state-owned utility or host country could also raise the buy-out payment by issuing bonds or borrowing from other sources. In either case, the likelihood that the state-owned utility or host government may not be able to close on such a transaction may be high enough—or may be perceived by investors and lenders to be high enough—to make it difficult for a concessionaire to raise debt financing.

It is worth noting, however, that similar issues have been successfully overcome in relation to concessions in the distribution sub-sector that were awarded in certain emerging markets. So although this risk may be difficult to overcome, experience has shown that it can be overcome.

3. Expropriation and nationalization risks

Thirty-three whole of network concessions in the transmission and distribution sectors in 16 emerging market countries have been reversed through the termination of concessions, nationalizations, and expropriations.[4] Although these types of events can in theory be policy driven and completed under a pre-agreed process which protects the legitimate interests of an investor on the one hand, and the government on the other, this is not always the case. Early termination is not usually the result of a successful concession arrangement and it carries significant risk for both the investors and the government. These experiences have caused investors to carefully consider a country's political economy, how a whole of network concession may be perceived in that political economy, and a country's long term level of commitment to such an arrangement.

Independent transmission projects

In contrast with a whole of network concession, an ITP involves the construction and maintenance of a single transmission line or a package of transmission lines. In emerging markets, these transactions are implemented under a long-term contract, generally between the state-owned utility that is responsible for transmission and the (private) project company that is established to undertake the project. Such a contract may be known as a transmission purchase agreement or a transmission service agreement.

Unlike a whole of network concession, in an ITP the project company is not obligated to expand the transmission line(s) it will construct, own, and operate. As a result, the host government, regulatory authority, or state-owned utility may conduct an auction to establish an annual revenue requirement or monthly availability payment. Although a portion of the annual revenue requirement or monthly availability payment that corresponds to the operations and maintenance expenses the project company will incur may be indexed, the majority of the annual revenue requirement or monthly availability payment will be fixed for the term of the project.

In order to support the ability of the project company to raise long term debt at attractive rates—which ultimately benefits consumers by lowering cost of the capital required for the project and thereby lowering the availability payment to the project company—the project company should be paid for the availability of the transmission line regardless of the quantity of power that flows over the line. In many cases, the auction that is conducted to select the investors is conducted by the regulatory authority, as is the case in Brazil, where the electricity regulator (ANEEL) conducts the auctions. Between 1999 and 2017 Brazil conducted 38 tenders for ITPs, resulting in the award of 211 projects with a combined length of over 69,000 km.[5]

Privatizations

A privatization by a sale of shares involves the sale of some or all of the shares in a state-owned enterprise to private investors. In the context of privatizing a utility in the transmission business, it would involve selling shares in that utility to private investors.

This model has been adopted by many high-income countries, including the UK, which privatized all of its transmission networks in three separate transactions in 1990. Experience with this model in relation to transmission in emerging markets is limited.[6] Although there is much to recommend this approach, as is the case with a whole of network concession, the requirement for independent regulation and the perceived risk of expropriation or nationalization may render this option difficult to achieve in practice in many emerging markets. In addition, discussions with officials in many emerging market countries has shown that many countries are reluctant to implement a transaction that would, in their minds, result in a significant loss of control by the government over assets that play such a central role in the deliver of an essential service.

Merchant lines

Merchant lines are transmission lines constructed by private investors who seek to profit by transmitting electricity from areas in which the cost of power is low to areas in which the cost of power is higher. Many of these lines are dispatchable high voltage direct current lines.

Although several successful examples of merchant lines exist, some merchant lines have been adversely affected by the growth of the transmission systems they connect, which reduced or eliminated the opportunity to profit by arbitrage. In many emerging markets, the risk that organic expansion of the existing transmission system may reduce or eliminate the profits that can be generated by a merchant line is particularly high given that the networks are not fully developed and are likely to grow.

In addition, a host country would need to affirmatively elect to allow the owners of a merchant line to earn returns that are significantly in excess of the returns that would ordinarily be earned by a regulated network utility. For these reasons, we see merchant lines as an interesting business model that may be attractive in unique circumstances but is not likely to be attractive—to either investors or host countries—in most cases.

Which models are most likely to succeed?

For the reasons described above, our view is that widespread private sector participation in the transmission sub-sector in most countries in emerging markets is unlikely to arrive in the form of the privatization of existing state-owned transmission utilities or merchant lines.

Whole of network concessions offer many benefits. They may be particularly attractive to countries that need to fund significant extensions, upgrades, and expansions of national transmission systems and would like to harness private sources of capital to fund those extensions, upgrades, and expansions. Whole of network concessions may also be attractive to governments that believe that a privately-owned concessionaire would be better placed to maintain and operate an existing transmission network, which would increase the overall availability of the system, improve the overall efficiency and utilization of the network, and thereby decrease costs to consumers on a per-unit basis.

While whole of network concessions offer many benefits, they also require host countries, investors, and lenders to overcome what can be significant issues in the context of many countries in emerging markets. Those issues include the three we highlighted above and some additional issues we will explore in a subsequent article.

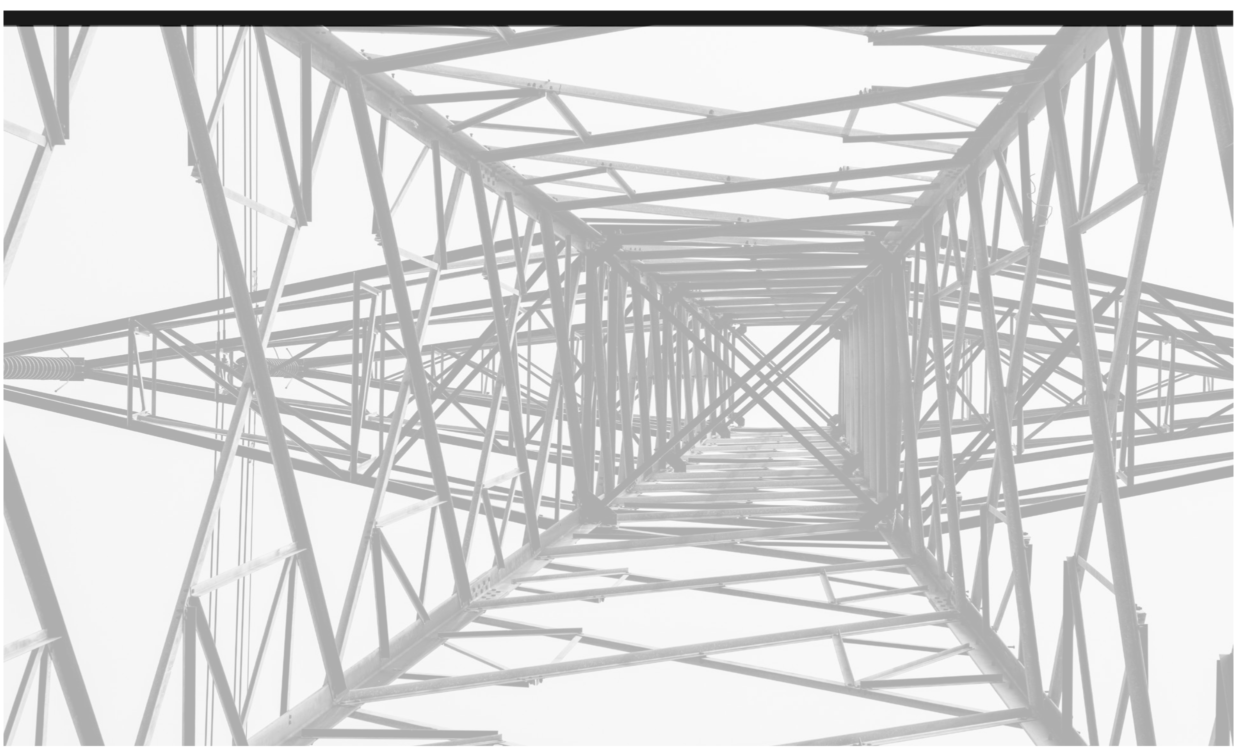
In contrast, ITPs offer several advantages. Some of the principal advantages follow.

- The first two risks we highlighted in relation to whole of network concessions (economic regulation and buy-out payments) can be avoided altogether.
- It is more practical to raise capital for ITPs using project finance techniques than it is to capital for whole of network concessions using project finance. Fundamentally, project finance separates out the cash flows and the risks that are related to a particular investment from the cash flows and the risks that are related to other investments. Single transmission lines or packages of transmission lines offer much better opportunities to separate cash flows and risks than do whole of network concessions.
- Independent transmission projects allow countries to conduct competitive tenders in relation to discrete projects as the need for those projects arises. This means that countries can gain valuable experience in structuring projects and conducting tenders. Likewise, investors gain confidence as a country establishes a track record of conducting well-structured and transparent tenders, leading to lower costs for successive projects.

In part because of these advantages, significant investments have been funded using the ITP model. Over 50,000 km of transmission projects have been constructed using the ITP model in Brazil alone. Peru, India, Chile, and other countries have also successfully implemented these projects at scale. Significantly, the experience in these countries has demonstrated that ITPs are often implemented at a fraction of the anticipated cost. In Peru, for example, the capital cost of ITPs was, on average, 36% less than the expected cost. Brazil's experience with ITPs resulted in similar cost reductions.

Given these factors, we view ITPs as a promising avenue for private investmentin transmission in emerging markets, followed by whole of network concessions. In subsequent articles, we will examine some of the considerations that go into structuring both ITPs and whole of network concessions. ■

1.IEA Southeast Asia Energy Outlook, 2022, pg. 69.
2.See Linking Up: Public-Private Partnerships in Power Transmission in Africa, World Bank, 2017.
3.See Extending Competition in Electricity Transmission: Impact Assessment, 2016, by Ofgem.
4.See Rethinking Power Sector Reform in the Developing World, Vivien Foster and Anshul Rana, 2019, pg. 14.
5.Linking Up, pg. 39.
6.Id.



An Introduction to Independent Transmission Projects

Overview

Although experience with ITPs in many emerging markets is virtually non-existent, they have been used extensively in Latin America, India, the US, and the UK. An ITP is a good way to attract capital into the transmission sector to fund key infrastructure and to transfer risk (such as construction risk) to the private sector. To implement an ITP, a host country grants a project company established by an investor or group of investors the right, and the obligation, to construct, own, and maintain a specific piece of transmission infrastructure. This is most commonly a single transmission line or a group of transmission lines, but the principle can be applied equally to substations or storage assets. This grant of rights (and obligations) can take a number of forms but is usually set out in an agreement between the state-owned enterprise that is responsible for transmission (the "state-owned transmission company") and the project company.

The most common names for such an agreement are a Concession or a Transmission Services Agreement. At the same time, the ministry that is responsible for overseeing the electricity sector, or the regulator, grants a license to the project company to carry out transmission activities. Unlike a broader whole of network concession, in an ITP the project company is not obligated to expand the transmission infrastructure it will construct and own.

This means that an ITP can be a relatively narrow intervention in the electricity sector. A discrete project can be scoped and allocated to an investor or developer. Although the aim of many countries is to reach a point where a transmission utility may conduct an auction for packages of lines, in order to drive down construction and financing costs to the lowest possible level, it's likely that the first such ITPs in many jurisdictions will be bilaterally sourced.

For instance, many transmission utilities in sub-Saharan Africa are at present bilaterally sourcing a portion of their transmission infrastructure under an EPC, plus financing a model in order to pass development risk to the private sector, which is also responsible for conducting feasibility studies and scoping the project. This model can be applied to the financing of ITPs and there are helpful fiscal policy advantages to using private sector models rather than traditional forms of financing that require sovereign guarantees.

In order to support the ability of the project company to be financed at attractive rates—which ultimately benefits consumers by lowering cost of the capital required for the project, which in turn lowers the payment made to the project company— the project company is typically paid for the transmission line regardless of the quantity of power that flows over the line. These fixed payments mean that only limited regulation is required once a project is established.

Arrangements for the maintenance of the line for the duration of the Concession or Transmission Services Agreement will be agreed when the project is designed and this may be the responsibility of either the project company or the state-owned transmission utility. If it is the responsibility of the project company, then the cost of maintenance will be reflected in payments made to the project company by the state-owned transmission facility. In this case, the payments may also be based on the "availability" of the line for the duration of the concession so that the project company is rewarded for maintaining the line appropriately and penalized if the infrastructure is not available to be utilized at the agreed level. If the project company is not responsible for maintenance then payments for the line are more likely to be characterized as lease payments or an annuity.

A unique feature of ITPs is that they are operated as part of an integrated transmission system, not by the project company. The state-owned transmission utility or transmission system operator (if those functions have been separated) operates a transmission line developed as part of an ITP by dispatching generation and balancing the system of which the transmission line is a part just like it would operate any other transmission line. This feature may be particularly attractive where there is some reluctance to allow the private sector to control the dispatch of generation resources.

An ITP may be appropriate if a host country:

- is, as a general matter, pleased with the performance of the state-owned transmission company and desires to see the state-owned transmission company continue to operate in its current form;
- desires to construct a significant transmission project or group of transmission projects without assuming the construction risk for those projects;
- would like to use private capital to fund those transmission project(s);
- would like to unlock sources of debt financing that are not available to the state-owned transmission utility; or
- would like to avoid on balance sheet borrowing by structuring the projects to achieve off balance sheet treatment.

An ITP may be less attractive to a host country that:

- has access to sufficient funding to meet its sector financing needs on suitable terms; or
- is looking for a new operating model for the wider network because its existing system operator has not been able to achieve performance indicators, service levels, or other commonly used performance benchmarks.

As a country considers whether an ITP is an appropriate tool for achieving its objectives, it should also consider how electricity sector participants and other stakeholders will be affected, and how to engage with those stakeholders to build support for the transaction.

Enabling environment

One of the benefits of ITPs, particularly in comparison to concessions or privatizations, is that they can be implemented in enabling environments that would present some challenges for concessions or privatizations. In other words, the requirements on the enabling environment are significantly easier to meet. Ideally, the legislative position in the country and other aspects of the enabling environment would include a suitable licensing regime and a clear authority from government to the sector regulator or the state-owned transmission utility to award ITPs to project companies.

Note that an independent regulator is not necessary. Neither is it necessary for the host country's utilit(ies) to have been unbundled into separate utilities responsible for generation, transmission, and distribution. Although they would be useful, clearly defined codes that govern the conduct of sector participants (such as a grid code, a distribution code, or a dispatch code) are not required either. As a result, the independent transmission project model is inherently flexible and can be deployed in countries that would find it far more challenging to implement a concession or a privatization.

Contractual structure

There are many similarities between an ITP and an independent power project. Both structures involve a single project (a generation plant or transmission infrastructure), or a small group of projects in the case of an ITP. Both structures are designed to separate a stream of cash flows, rights, obligations, and risks in order to facilitate the use of project financing techniques. Given these similarities, it should not come as a surprise that there are similarities between the contractual structures for ITPs and independent power projects.

For independent power projects, the contractual structure of the Transmission Services Agreement or Concession would, among other things:

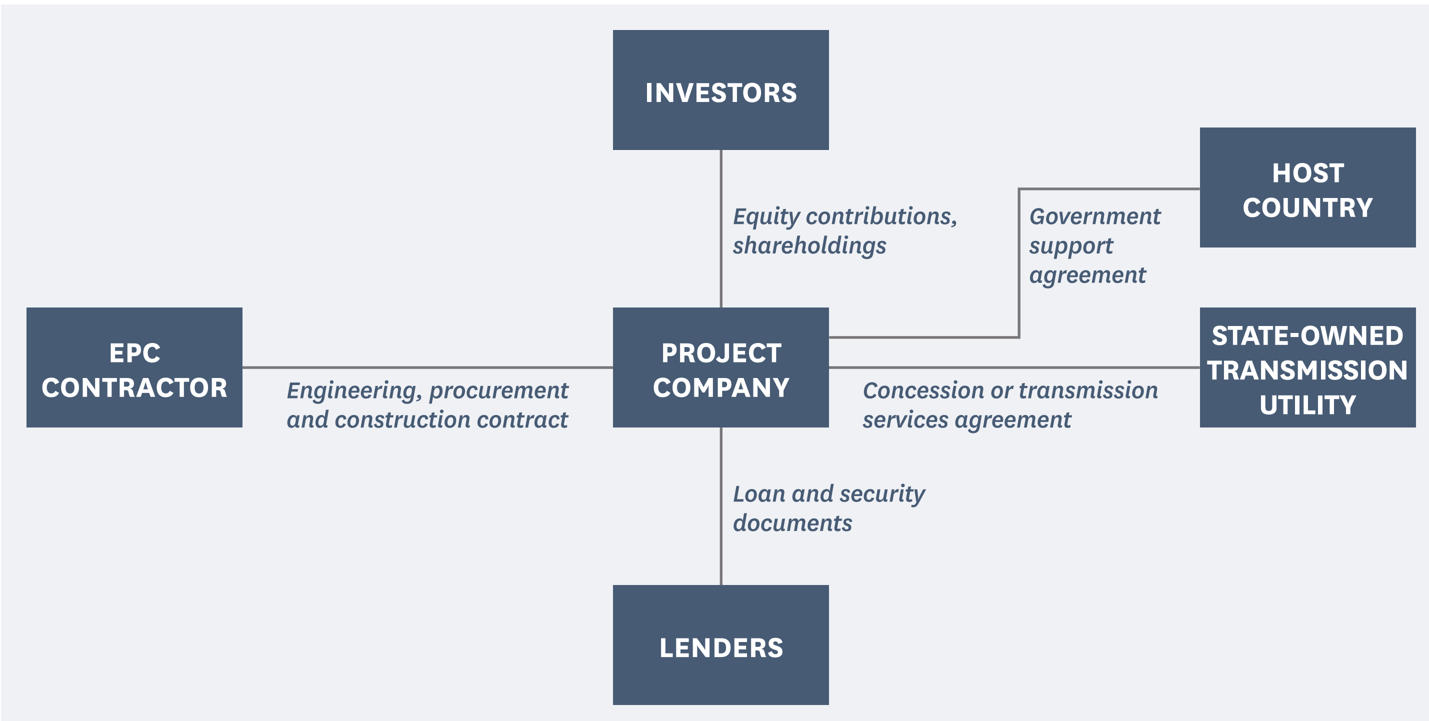
- obligate the project company to design, engineer, procure and construct, the project;
- obligate either the project company or the state-owned transmission utility to maintain the infrastructure;
- obligate the project company to make the capacity of the transmission infrastructure that constitutes the ITP available to the state-owned transmission utility; and
- obligate the state-owned transmission utility to purchase the transmission capacity and make the payments that are specified in the Transmission Services Agreement or Concession.

The state-owned transmission utility would be obligated to purchase and pay for the transmission capacity made available regardless of the quantity of energy that is actually transmitted by the project.

If the project company is responsible for maintenance, then the payments that are payable by the state-owned transmission utility would be reduced to the extent transmission capacity is not made available. The reductions to the availability payments would be weighted by the amount of time the transmission line(s) are not available and, in the case of a partial de-rating of a transmission line, the extent of the de-rating. This type of mechanism will facilitate the use of project financing techniques and ensure that the project company has an appropriately firm incentive to properly maintain the transmission line(s) and make transmission capacity available to the state-owned transmission utility.

The government support agreement would contain terms that are similar to those found in a government support agreement entered into in relation to a generation project. The agreement would also include appropriate termination payments. Those termination payments could take the form of a put option and a call option of the type that would typically be found in a put and call option agreement. For a discussion of put and call option agreements and how to calculate termination payments and purchase prices, see our Africa Projects resource center.

Like all projects that are financed using project finance techniques, allocating risks properly—to the party that is best able to manage the risk and, to the extent that no party is best able to manage a risk, to the party that is best able to bear the risk—is essential to attracting debt financing on terms that will result in good value for money to the offtaker (in this case, the state-owned transmission utility).



Allocating Risks in Independent Transmission Projects

Allocating risks

One of the benefits of ITPs is that they can be structured to take advantage of project finance techniques. Some of the advantages of properly structured project financed transactions are (i) the ability for a project to be financed with higher debt to equity ratios, and (ii) the ability for the project company to achieve longer loan tenors. These advantages have the effect of lowering the cost of the services delivered by the project (in this case transmission capacity). One of the keys to raising debt for project financed transactions is an appropriate allocation of risks. Risks should be allocated to the party that is best able to manage each risk, and if no party is best able to manage a particular risk, it should be allocated to the party that has the most to gain from the project. As a project is structured, all of the parties involved in the project should seek to identify and assess the risks that may arise. In practice this means that most of the parties involved in a project will engage a wide range of advisors—including technical, financial, and legal advisors—to identify and assess those risks. The risk matrix you can download below illustrates how a range of risks might be allocated in a typical ITP transaction where principles followed in other markets are applied to emerging markets. In practice there will be a range of approaches to each of these issues.

There are many markets where ITPs have been successful in significantly reducing transmission costs. Where ITPs are rolled out at scale in a country, the risk allocation matrix used is likely to be set by Government and tendered to bidders under a centrally managed tender process. In such examples, the host Government will need to invest resources in developing the individual transmission projects to a point where they are capable of being tendered. This will typically take at least three to four years to carry out detailed feasibility studies and appoint transaction advisers to design and run a transparent tender process.

For these reasons, and also because there are many urgent transmission projects which have stalled due to lack of available funding, the authors believe it is likely that the first transmission projects on the continent will be bilaterally negotiated ITP projects that establish a precedent for future investment in the sector. These are likely to give rise to bespoke risk allocations which reflect the specifics of individual projects and financier's appetite or ability to manage certain risks in comparison to a host national transmission utility. They are also likely to pass more early stage risk and cost to developers than would be possible for a tendered project.

Regardless of the process used to develop ITPs in emerging markets, it is likely that they can be used to improve sector sustainability in many markets by providing a flexible and efficient solution in a market which has not yet received the same level of investment as power generation. Unlocking financially accretive projects which improve system performance and allow more power to be sold is important to sector finances.

Significant further transmission investment is also necessary to support increased renewables in the generation mix in most countries as part of a transition to clean energy. ITPs are perhaps the best near term model in many markets for achieving this level of investment since they can be implemented relatively quickly and do not typically require material sector reform.

Risk	Who Bears the Risk?	Comments
Financial		
Demand risk	State-owned transmission company, Consumers	Demand risk is effectively allocated to the state-owned transmission company through the use of an availability payment. In a well-regulated sector, the demand risk would be reallocated to consumers by the tariff methodology that is used to regulate the state-owned transmission company or to establish the rates paid by consumers.
Credit risk	Host government	Unless a state-owned transmission company has an investment grade credit rating—which is highly unusual in emerging markets—some form of credit support for the payment obligations of the state-owned transmission utility will be necessary. This may take the form of a sovereign guarantee, a partial credit guarantee, partial risk guarantee, or a put and call option agreement combined with liquidity support. Each of these forms of support is likely to have a different fiscal treatment. The more robust the form of support available, the lower the credit risk and therefore it is likely that a lower cost of capital will be available to fund the project. In many African countries sovereign debt capacity is a limiting factor for expansion of transmission networks at present and offering a put and call option agreement with liquidity support to mitigate credit risk may be a good solution to support private investment.
Inflation	Consumers	Inflation is normally reflected in increased power costs to consumers over time. The extent to which it needs to be specifically apportioned to a party under ITP Project Contracts will depend on the structure of payments. The most obvious example of where inflation may become a risk is in the situation where a project company is required to carry out O&M of the transmission infrastructure that it owns. If this is the case, the O&M component of the availability payment will typically be adjusted for inflation by a regulator over the term of the contract.
Interest rates	Project company	In most cases, the level of the availability payments will not change depending on changes in interest rates. This may represent a refinancing risk for a project company if the project company cannot borrow at fixed interest rates or if the tenor of loans from lenders does not match the length of the Transmission Services Agreement. Risk mitigants may include hedging products but the availability and price of these for long term local currency in African markets at present renders it difficult to use them.
Foreign exchange rates	State-owned transmission company with risk passed on to Consumers through tariff changes	In markets with strong availability of long-term local currency debt it may be possible to denominate part of the availability payment in local currency.

Risk	Who Bears the Risk?	Comments
Land		
Land acquisition	State-owned transmission company	The cost of acquiring the rights of way, easements, and other interests in land that are required by the project may be borne by the state-owned transmission utility or the project company, regardless of which of them is responsible for acquiring those interests. The acquisition of all of the required interests in land would typically constitute a condition precedent to the first disbursement of the project's loans.
Technical		
Construction and commissioning of new assets	Project company	The project company is responsible for constructing and commissioning new assets.
Operations and maintenance, technical performance	State-owned transmission company or project company	The maintenance of the assets can either be the responsibility of the state-owned transmission company or the project company. Factors in determining which is the best approach may include (i) how closely integrated the assets are in the existing transmission network maintained by the state-owned transmission company, (ii) how effective the state-owned transmission company is with current O&M operations, (iii) the scale of the assets, and (iv) Government policy in this respect. How the payment under the Transmission Services Agreement is calculated (and the extent to which it may be variable) will typically depend to some extent on whether the project company is responsible for maintaining the assets and ensuring their availability or whether its responsibilities are narrower and only pertain to developing, funding and constructing the assets. The variability of payments based on availability/performance are the means through which risk is passed to the project company if it is responsible for maintenance. It is likely that the project company will also take risk on variations of the cost of providing these services over the period of the Transmission Services Agreement, subject to periodic adjustments for inflation.
Licenses and Permits		
Initial issuance of licenses and permits	Government, state-owned transmission utility, and project company	The project company must apply for and diligently prosecute its applications for all licenses and permits. Significant licenses are granted prior to financial close and usually have a term that is the same as the term of the transmission purchase agreement. If a public authority fails to grant a license or permit when the applicable requirements have been met, that failure would typically be treated as a political force majeure event.
Renewals, modifications	Government, state-owned transmission utility	A failure to renew a license or a modification to the terms of a license that effectively prevents the project company from performing its obligations or exercising its rights under the concession will constitute a change in law which will normally be dealt with as described below.

Risk	Who Bears the Risk?	Comments
Social & Environmental		
Social and environmental impacts	Project company	The project company will typically be responsible for conducting social and environmental impact assessments, complying with the stakeholder consultation and environmental laws of the host country, and, if the project company's lenders are party to the Equator Principles, for complying with relevant performance standards issued by the International Finance Corporation.
Occupational health and safety	Project company	The project company is responsible for complying with the occupational health and safety laws of the host country, and, if the project company's lenders are party to the Equator Principles, for complying with relevant performance standards issued by the International Finance Corporation.
Extraordinary Events		
Changes in law	Consumers, government	Changes in law that increase the costs incurred by the project company or decrease the revenues earned by the project company should be addressed through changes to the availability payments or by one-time payments, depending on the nature of the change in law. To the extent they are not, they should be addressed through a change in law clause in the government support agreement, which will typically provide certain remedies to the project company in respect of changes in law. Those remedies may include the payment of a termination payment and transfer of the assets to Government.
Changes in tax	Consumers, government	Changes in tax that increase (or decrease) the tax obligations of the project company should be addressed through changes to the availability payments. To the extent they are not, then they should be dealt with through a change in law clause in the government support agreement.
Force majeure events	Project company, consumers	The project company must mitigate the effects of force majeure events to the extent possible. Where it is practical to do so, the project company will be required to insure against these risks.
Political force majeure events	Consumers, government, state-owned transmission utility	If the project company is prevented from performing its obligations or exercising its rights under the project agreements in a manner that is material due to the occurrence of a political force majeure event and the effects of such events continue for a prolonged period of time, an event of default may occur under the transmission purchase agreement and the government support agreement.
Disputes		
Resolution of disputes under contracts	n/a	Disputes arising under the project agreements are resolved by international arbitration to the extent they are not resolved informally.

Concessions Part 1

Overview

A concession is a right to develop, construct, operate and maintain an infrastructure project and to earn profits paid from a share of the revenues generated by the project. Concessions are typically granted by a government, public authority, or state-owned enterprise. A concession may be granted pursuant to a concession agreement, a lease, a lease and assignment agreement, a project development agreement, or similar agreement. In most countries, the name of the agreement that grants the concession is not important. Instead, the rights and obligations created are the defining features of a concession. Although the name of the agreement is not important, we will refer to it as the concession agreement.

A concession may be appropriate if a host country desires to:

- leverage the experience and know-how of the private sector to improve the performance of a transmission utility;
- increase budget certainty by transferring the responsibility for financing capital expenses from the public sector to the private sector;
- reduce the risks borne by the public sector by transferring responsibility for the development, financing, and construction of projects that are required to expand, reinforce, and upgrade the transmission system; and
- use private capital to finance significant improvements to, or significant expansions of, a transmission system, while retaining ultimate ownership over the transmission system and the ability to terminate the concession if the concessionaire fails to perform its obligations under the concession agreement.

A concession may be less attractive to a host country that:

- has an existing transmission utility whose performance equals or exceeds international benchmarks;
- is able to raise funding on suitable terms (either based on the balance sheet of the existing transmission utility or though public resources) to fund any network investment required; or
- is mainly interested in raising financing for a discrete transmission project or a package of discrete transmission projects (which may be achieved more quickly and efficiently using other models such as the IPT model).

Although there are a number of whole of network concessions over unbundled electricity distribution companies in many emerging markets, the authors are not aware of a transmission company that has been the subject of a concession save for in Cameroon where a combined transmission and distribution concession was granted in 2001 before transmission was taken back into state control in 2021. Given the very significant funding required to expand the transmission networks in many

African countries to meet energy access targets and transition to an increased share of renewable energy in the generation mix, it is likely that this form of private sector participation will be used in some markets in the foreseeable future.

A whole of network concession would be a significant change to a sector if implemented in most countries. If a government considers that a concession is an appropriate tool for achieving its objectives, it will also need to consider how the role of electricity sector participants will be changed by the concession, how stakeholders will be affected, and how to engage with those stakeholders to build support for the transaction.

Enabling environment

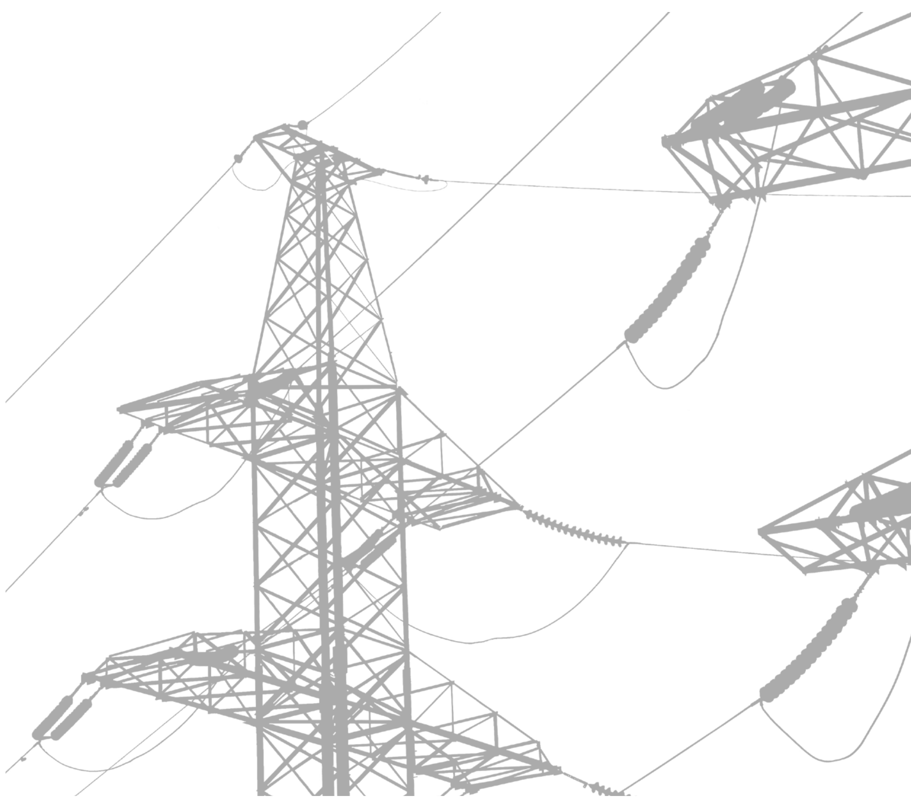
Network industries require ongoing investment. As a result, even a concession over of a transmission system that does not require significant expansion will require the concessionaire to incur capital expenditures to replace worn-out equipment, restore and refurbish existing equipment, and upgrade the transmission system as a whole over the term of the concession. In most African jurisdictions, it is likely that a concessionaire will be required to commit significant funds to expand the transmission network over the course of the concession to meet energy access targets. As a result, the rates that are charged by a concessionaire for transmission service cannot be set and fixed at the beginning of the concession.

Instead of establishing rates for the term of the concession at the outset, one of two approaches is usually adopted. The most common approach is for a concessionaire to be subject to technical and economic regulation by an independent regulator. The regulatory approaches regulators use to regulate utilities generally, and concessions in particular, will be covered in a separate article. These approaches require that a regulator articulate the methodologies it intends to use to regulate the concession in a set of tariff guidelines or a tariff methodology.

In the alternative, a government support agreement or concession agreement may include an annex that describes a regulatory methodology in essentially the same terms in which a set of tariff guidelines or a tariff methodology would describe it. The parties to the government support agreement (the host country and the concessionaire) or the concession agreement (the state-owned transmission utility and the concessionaire) will then be responsible for applying the regulatory methodology following the terms of the contract. If and when an independent regulator is established, that regulator can play a significant role in applying the regulatory methodology if the government support agreement and concession agreement contemplate that outcome. This system is known as regulation by contract.[1]

Regulation by contract is more likely to be used in a market where there is insufficient regulatory capacity at the point when a concession is granted. Regulatory risk (including lack of regulatory track record) will be a key factor for investors in deciding whether they can support a transmission concession, and the level of returns that they will require. The returns required by an investor (often described as the cost of capital) have an impact on end user tariffs and it is therefore normally in both the government's and the investor's interests to reduce regulatory and tariff based risks as much as possible.

Legislative frameworks will vary from country to country, and as described above, there are a number of legal forms that a concession can take. However, it is often the case that the legislative framework and other aspects of the enabling environment in which a concession will be implemented would include:



1. an Act (such as a Public-Private Partnership Act) that (i) establishes the framework under which public-private partnerships are studied, structured, and awarded, (and (ii) clearly defines the role of contracting authorities and the government in structuring and awarding public-private partnerships;
2. clear authority for the government, the sector regulator, or the state-owned transmission utility to award a concession over the transmission assets;
3. an independent regulator which issues licenses to utilities that operate in the electricity sector and regulates those utilities;
4. utilities that have already been functionally unbundled into generation, transmission, and distribution (as opposed to a single vertically integrated utility);
5. independent power projects (which will have given the host country, the regulator and other sector participants experience with private sector participation in the electricity sector); and
6. clearly defined roles for generation, transmission, and distribution and clearly defined codes that govern their conduct and establish technical standards (such as a grid code, a distribution code, and a dispatch code).

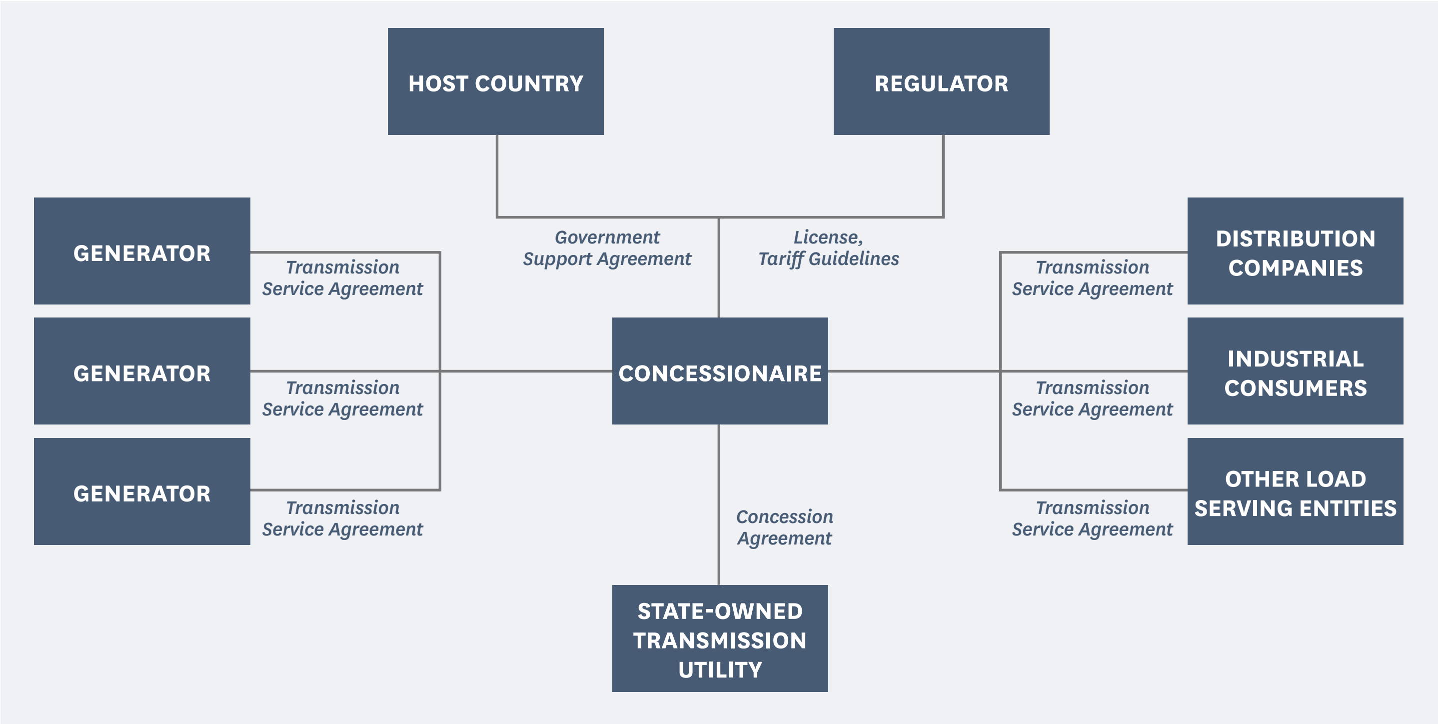
However, as the discussion above as to how to use regulation by contract to achieve the seemingly impossible task of implementing economic regulation in a country that has not established an independent regulator shows, with enough creativity, a sector that lacks some of the above features of an enabling environment can still implement the concession model.

Contractual structure

In a typical transmission concession, a state-owned utility that owns a transmission system (the "grantor") grants a concession over its transmission network to a project company established by the investors to act as the holder of the concession (the "concessionaire"). At the same time, the ministry that is responsible for overseeing the electricity sector, or the regulator, grants a transmission license to the concessionaire. In addition, the host country may enter into a government support agreement, implementation agreement, or similar agreement (a "government support agreement") with the concessionaire to provide certain identified types of support to the transaction.

Collectively, the concession agreement and the transmission license typically provide that:

- the grantor will retain ownership of the existing transmission system and lease the existing transmission system and related assets to the concessionaire;



- the grantor utility will lease or sell to the concessionaire all of the state-owned transmission utility's moveable property, equipment, and inventory of spare parts;
- the grantor will transfer some of the contracts to which it is a party—which may include on-going service contracts, contracts for the supply of goods and equipment, and contracts for the construction or supply of new assets that will become a part of the transmission system—to the concessionaire;
- the concessionaire will pay a concession fee, which may be structured as a one-time payment, on-going payments, or a combination thereof;
- the concessionaire will use the leased assets and the transferred assets to provide transmission service within the service territory described in the transmission license;
- the concessionaire will improve, repair, operate and maintain the transmission system;
- the concessionaire will expand, reinforce, and upgrade the transmission system to the extent required to provide transmission service within the service territory, and to the extent that expansion projects are approved by the regulator in accordance with the tariff guidelines.

The participants in a concession and their contractual relationships are shown in the diagram on page 18.

The diagram assumes that the grantor does not also function as a single-buyer (the purchaser under all power purchase agreements) and the supplier to distribution companies, industrial consumers, and other load serving entities. If it does, then either the grantor may continue to serve that function or the concessionaire could assume that function by entering (i) into a bulk supply agreement with grantor (under which it would purchase the capacity made available by, and the energy generated by, generators from the grantor), and (ii) separate bulk supply agreements with the distribution companies, industrial consumers, and other load serving entities to which it supplies energy. Both approaches involve some complexities that are outside the scope of this article. For our purposes the important point is that these complexities exist but can be overcome.

As the concessionaire constructs and installs new equipment and facilities and those facilities become part of the transmission system, legal title to the new equipment and facilities vests in the grantor so that the grantor remains the owner of the entire transmission system during the term of the concession. If, for example, the concessionaire needs to acquire additional rights of way, easements, ownership interests, or leasehold interests in land to expand the transmission system, the concessionaire acquires those interests in the name of the grantor, and those interests become subject to the leasehold interest and access rights created by the concession.

The concessionaire will be responsible for operating and maintaining the transmission system. If the legislative framework provides that the holder of a transmission license is responsible for dispatching generation and balancing the system, then the concessionaire will be responsible for those functions. If the legislative framework contemplates that those functions will be performed by a separate transmission system operator, then those functions will be performed by the entity that holds the license to act as the transmission system operator. It is important to think about the transmission system operator role as being possible to separate from the role of investing in and maintaining the network, because some governments regard the TSO role as being strategically sensitive.

The concessionaire will recover its ongoing operations and maintenance fees from the use of system fees it charges for transmission. It will finance capital expenditures to upgrade and expand the transmission system with a combination of debt and equity. Equity will be contributed by the shareholders in the concessionaire or created through the retention of earnings by the concessionaire. The concessionaire will raise debt by borrowing from lenders or by issuing bonds or preferred shares. The concessionaire's ability to raise capital in the form of equity, debt, and preferred shares is highly dependent on several factors. Of these, the most important are:

- how the concessionaire is regulated;
- how the buy-out payment (a payment that is payable by the grantor upon the expiration or termination of the concession in respect of the undepreciated portion of the investments made by the concessionaire) is structured; and
- how risks are allocated. ■

1 See Tonci Bakovic, Bernard Tenenbaum, and Fiona Woolf, *Regulation by Contract – A New Way to Privatize Electricity Distribution?*, 2003.

Concessions Part 2

Economic regulation: a brief overview

The central problem that economic regulation must solve is to ensure consumers of power are protected from the ability of a monopoly to charge prices that are not reasonable, while assuring investors that their long term investment will be fairly rewarded and that they will be protected from populist pressure to reduce prices to a level which does not allow for this.

As a general rule, legislative frameworks that govern electricity sectors establish an independent regulator – a separate and independent legal entity that is responsible for technical and economic regulation. Although the government may establish policy objectives for the sector, the regulator is responsible for ensuring efficiency, transparency, and fairness in the management of the electricity sector and benefits from the discretion that is required to achieve those objectives and to balance the interests of investors and consumers.

As discussed in previous articles in this series, the role of the regulator in a typical ITP Project is likely to be limited to reviewing a project prior to financial close, licensing it, and ensuring that any licensing conditions or KPIs are adhered to. In contrast, the role of an electricity regulator in a sector with a whole of network transmission concession is much more substantial. Whole of network concessions are a more complex business model. The concessionaire will be responsible for operating, maintaining, and usually also expanding the network to meet the transmission needs of customers in the concession area over a long period of time. The costs associated with this (including operating costs, capital investments and financing costs) are dynamic over that period of time, and tariffs will need to be adjusted to recognize changes in these costs. Tariff guidelines will typically be in place when a concession company makes investments in the network and the regulator will be responsible for applying those guidelines, approving operating costs and capital investment plans, and monitoring the transmission utility's performance. The concept of regulatory independence and discretion mean that a regulator may also be permitted by law to modify its tariff guidelines at any time.

Risks around regulatory discretion and the track record and experience of the relevant regulator are a major factor for investors in deciding whether they can fund a transmission concession, and if so, what the risk premium applied to calculate their returns should be. As a result, a government support agreement is usually entered into in relation to a whole of network concession, and it usually containing a change in law clause which provides that if (i) the regulator modifies the tariff guidelines, fails to apply the tariff guidelines, or issues decisions that are contrary to the tariff guidelines, and (ii) the action (or inaction) of the regulator decrease the revenues earned by the concessionaire or increase the costs incurred by the concessionaire without affording the concessionaire a reasonable opportunity to recover those increased costs, then the host country will compensate the concessionaire. That compensation may take the form of a one-time payment or an ongoing subsidy to the concessionaire, depending on the nature of the action taken by the regulator.

The frameworks that are used to regulate network industries can be classified into two general approaches—the cost-of-service approach and performance-based regulation. Although many of the concepts involved in these approaches are similar, there are some key differences that are worth highlighting as we explore these two approaches.

Cost of service regulation

The traditional cost-of-service approach to regulation was developed in the U.S. at the beginning of the 20th century. The first step in determining rates using the cost-of-service approach is to determine the annual revenue requirement for the utility being regulated. The annual revenue requirement is the total amount of revenues that the utility must earn to recover its costs and earn a reasonable return on its investments. The basic formula for establishing the annual revenue requirement is as follows:

Where:

$$\mathbf{ARR_y = (RateBase_y \times WACC_y) + Depreciation_y + O\&M_y + Tax_y}$$

ARR_y	means the annual revenue requirement for year 'y';
$RateBase_y$	means the value of the assets of the utility that are useful in delivering the service provided by the utility and are used by the utility for that purpose at the beginning of year 'y';
$WACC_y$	means the weighted average cost of capital approved by the regulator for use during year 'y';
$Depreciation_y$	means the amount of depreciation that the utility will recognize during year 'y';
$O\&M_y$	means the expenses that an efficient utility would incur to operate and maintain the assets in the rate base and otherwise perform the function of delivering the utility's services to its customers during year 'y'; and
Tax_y	means all of the taxes incurred by the utility during year 'y', including ad valorem taxes, corporate income taxes, and other taxes.

These terms are further explored below.

The Rate Base

As a general rule, at least in the context of cost-of-service regulation, the rate base is determined by using the historic acquisition cost of each asset within the rate base and subtracting the depreciation that has accumulated since the asset was placed into service, usually using straight line depreciation.

The weighted average cost of capital

The weighted average cost of capital may be determined by the regulator using the following process.

- First, the regulator establishes a target debt to equity ratio for the utility, which may be expressed as X%:Y%. When expressed in that form, X is the total debt of the utility divided by the total capitalization of the utility (the sum of debt and equity) and Y is the equity of the utility divided by the total capitalization of the utility.

- Second, the regulator determines a cost of equity for the utility. The cost of equity may be determined by using the capital asset pricing model, which describes the relationship between the risk of investing in an enterprise and the expected returns. The capital asset pricing model starts with a risk-free rate of return and adds a risk premium (which is based on the beta of investments in that sector, which is a measure of the volatility of investments in the sector compared to the volatility of investments in a market generally) and, for investments that are not liquid (such as an investment in a closely held utility, as opposed to a publicly held utility), a liquidity premium, to estimate the returns the investment must generate to incentivize investors to invest in the enterprise.
- Third, the regulator determines the cost of debt for the utility. This may be determined by benchmarking the cost of debt for similar utilities or the cost of debt for large corporate borrowers generally, which can be estimated by drawing comparisons to an index of yields on bonds issued by corporate borrowers (for example).
- Finally, the cost of equity and the cost of debt are weighted by X and Y to determine a weighted average cost of capital.

The steps described above are regularly used in mature regulated electricity markets with a history of privately operated utilities such as those found in North America, Western Europe, Australia, and New Zealand to name just a few. The set of laws, rules, caselaw, and normative expectations that makes the level of discretion described above possible is generally referred to as the "regulatory compact". In those countries, the regulatory compact has evolved and stabilized over the course of 100 plus years. In markets which may be putting a whole of network concession in place for the first time (as would be the case in many emerging markets) it is likely that neither investors nor lenders would be be able to bear the risks that would be created by granting that level of discretion to a regulator without the same long-term track record. There is also the added complication that debt markets are likely to be less liquid and will provide fewer obvious reference points. As a result, countries that are seeking to implement a whole of network concession for the first time may need to reduce those risks in order to incentivize investment. This could be achieved by (i) allowing bidders to bid the return on equity, which would remain constant over the term of the concession, and (ii) allowing the concessionaire to pass through the actual cost of debt available to the utility (as opposed to the regulator setting the expected pricing). These are just two examples of the types of changes that could be made to reduce the risks borne by investors and lenders. Additional steps may be required.

Depreciation

The depreciation is calculated by applying the depreciation methodology established by the regulator for that sector to the assets that constitute the rate base. Straight-line depreciation is often used to calculate the depreciation component of the annual revenue requirement. To take a simple example, a regulator may establish a depreciation period of 30 years for an asset with a long service life, such as a transformer. In this example, a utility would recognize depreciation equal to 3.33% of the historic acquisition cost of the transformer each year over 30 years. Utilities maintain a register of all of their assets, including the historic acquisition cost of each asset and the depreciation it has recognized since the asset was placed in service so that it can perform these calculations.

The expenses that an efficient utility would incur to operate and maintain the rate base (the assets used to provide the service) and otherwise operate as a business can be determined by reviewing the expenses incurred to determine whether they were "prudently incurred". Prudently incurred costs can be described as those costs that are actually incurred and that could reasonably be expected to be incurred by a qualified, experienced, responsible and financially sound utility, acting reasonably, prudently, fairly and in good faith.

Stepping back for just a moment, it is easy to see the underlying rationale for the formula set out above. The component ($RateBase_y$ x $WACC_y$) provides a utility with a return on its investment. The component $Depreciation_y$ provides a utility with the return of its investment. The components $O\&M_y$ and Tax_y simply pass through costs incurred by the utility at the utility's cost. This in turn means that the only return on the investments made by the utility comes from the component ($RateBase_y$ x $WACC_y$).

Allocating the annual revenue requirement to consumers

After the annual revenue requirement has been established, it is allocated to consumers through end user tariffs which will typically be collected by a distribution utility and paid to the transmission concessionaire pursuant to a transmission service agreement or similar arrangement. The annual revenue requirement may be allocated to consumers by the quantity of the service supplied to the consumer (by the amount of energy consumed or transmitted for example) or, in some cases, by a measure of the value of the assets that are dedicated to serving that consumer (in the case of charges that are based on the peak demand of a consumer for example). In practice, the annual revenue requirement is typically divided into charges and rates that are established using a mixture of these concepts.

In a classic cost-of-service system, a utility files for a change to its rates when it would like to change the rates it is authorized to charge. In such a system, a utility's rates remain in effect until they are changed by the filing of a rate case and the issuance of a decision by the regulator that authorizes the utility to charge new rates. In practice, this expensive and time-consuming process often occurs annually.

Performance based regulation

The cost-of-service approach is vulnerable to problems caused by information asymmetry. Information asymmetry is a reference to the fact that the utility will always have better and more current information about its business than the regulator. A utility can use this information asymmetry to find ways to earn returns that exceed the returns it should earn.

Performance-based regulation addresses this and related problems by creating an incentive for a utility to become more efficient and thereby outperform the regulator's expectations. It works by establishing an annual revenue requirement for a period that is longer than one year. Such a period is known as the control period. Control periods generally fall within a range between three years and seven years. The annual revenue requirements for each year during a control period are established by the regulator in advance of the control period. If the utility incurs costs that are lower than the annual revenue requirements approved by the regulator, it can retain the difference as increased earnings. Although the utility may retain those earnings, the additional earnings come at a cost—at least when viewed from the perspective of the utility—the utility will have revealed to the regulator that it is capable of operating more efficiently and will have established a new benchmark for efficiency that the regulator is unlikely to ignore when it approves annual revenue requirements for the next control period. Conversely, if the utility incurs costs that are higher than the annual revenue requirements approved by the regulator, the utility's earnings will decrease. This arrangement effectively requires a utility to compete against itself and rewards a utility for operating efficiently.

A regulatory regime that uses performance-based ratemaking could involve the following series of steps.

1. Business plan

The utility submits a business plan to the regulator that:

- identifies the outputs the utility will be expected to deliver during the regulatory control period (including such outputs as safe, reliable and efficient transmission service to its existing customers, the connection of new customers in a non-discriminatory and timely manner, the expansion of the system where necessary, environmental improvements, security improvements and other outputs);
- reflects the views of stakeholders, as determined by a consultative process undertaken by the utility and the regulator; and
- contains a program of capital expenditures that sets out the capital expenditures the utility plans to make to deliver the outputs.

2. Regulated asset base

The regulator establishes the regulated asset base (the rate base) for the first year in the regulatory control period. The initial rate base may be established by privatization or by the award of a concession (depending on the structure of the concession). The regulated asset base is then (i) increased by the investments made by the utility, and (ii) reduced by depreciation. It is carried forward into each successive regulatory control period.

3. WACC, O&M, Taxes

The regulator establishes the weighted average cost of capital the utility is permitted to earn, the operations and maintenance costs that an efficiently operated utility would incur to operate and maintain the regulated asset base and otherwise perform its functions and a projection of the utility's tax liabilities.

4. Annual revenue requirement

The regulator sets the annual revenue requirement for each year during the regulatory control period by multiplying the regulated asset value for that year by the WACC and adding the efficient operations and maintenance costs and a projection of the taxes the utility will incur. Note that the regulated asset value for each year is set based on the then-current regulated asset value, the expected depreciation, and the investments carried out that have been approved by the regulator and will increase the rate base, as outlined in the approved business plan.

5. Rates

The annual revenue requirement is used to establish rates and charges in the manner described above in the section on cost-of-service regulation.

6. Smoothing

Rates are then smoothed from year to year, resulting in a constant increase (or decrease) to rates over the regulatory control period. These smoothed rates include an adjustment for projected inflation rates and account for the time value of money. They may also include an adjustment for projected changes to foreign exchange rates.

7. Inflation, foreign exchange adjustments

The projected inflation rates and foreign exchange rates are replaced by actual inflation rates and foreign exchange rates during periodic interim adjustments that occur at regular intervals during the control period. This is important because currency risks represent a major challenge for investors in African utilities where tariffs are collected in local currency, but financing is provided in hard currencies.

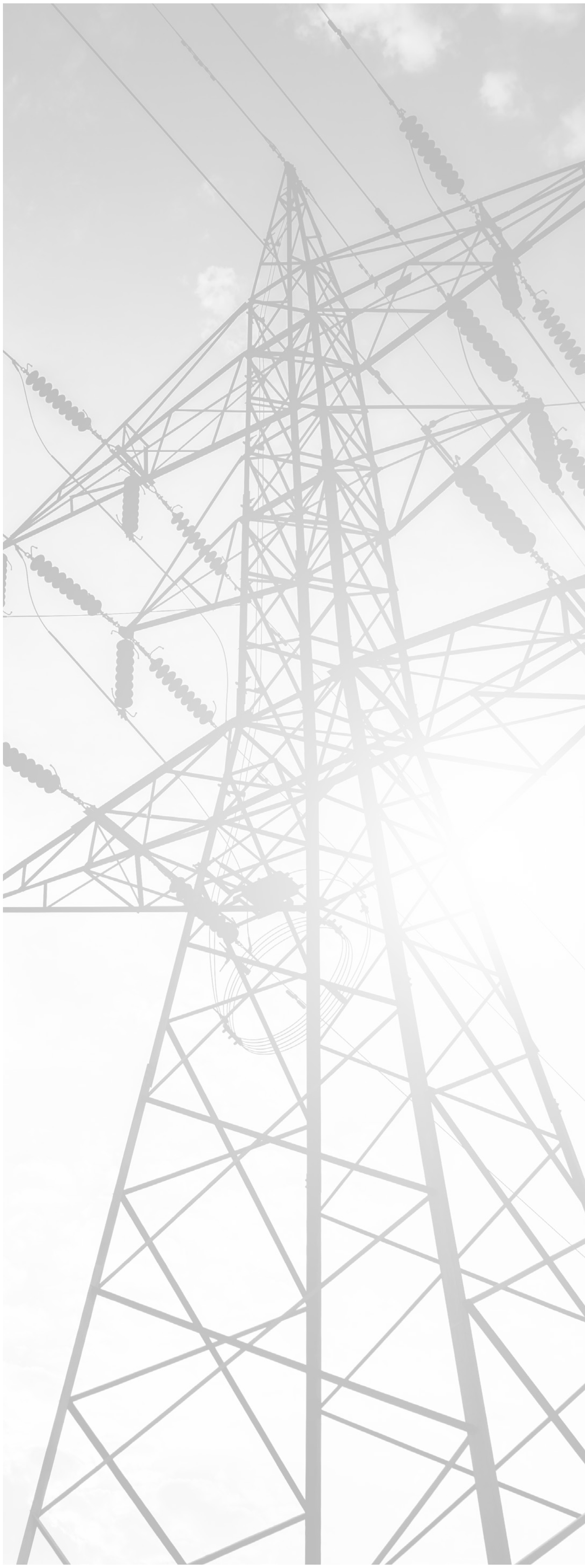
Options for establishing the regulated asset base

In many performance-based ratemaking systems, the regulated asset base is established based on the actual historic cost incurred minus accumulated depreciation, as is the case with traditional cost-of-service regulation. In other systems, the regulated asset base is revalued at the end of each control period to account for the inflation incurred during that control period. In these systems, the weighted average cost of capital is calculated in real terms, meaning that it does not include a component for inflation expectations. In other systems, the regulated asset base is adjusted at the end of each control period based on an estimate of the costs an efficient utility would incur to construct its facilities at the beginning of the control period, with an adjustment for the actual condition of those facilities.

In the context of a concession for a utility located in an emerging market, establishing the regulated asset base based on the actual historic cost incurred minus accumulated depreciation eliminates a few difficult problems that would be created by the other two systems (inflating the regulated asset base or revaluing the regulated asset base based on estimates of the then-current cost of construction). The most significant of these problems is that the latter two systems tend to increase the value of the regulated asset value over time. As we will see in the article on buy-out payments, the undepreciated value of the regulated asset base is used to calculate the buy-out payment a grantor must pay upon the expiration or termination of a concession. As a result, increasing the value of the regulated asset base increases the amount of the buy-out payment. A further problem is that the latter two systems increase the level of discretion granted to the regulator in ways that tend to reduce investor interest and impair the bankability of concessions.

Regardless of whether a regulator intends to regulate using cost-of-service or performance-based regulation concepts, the methodology it intends to be used should be clearly articulated in a set of tariff guidelines or a tariff methodology. In some systems, it may be possible for the tariff guidelines or tariff methodology to be set out in a schedule to the government support agreement or implementation agreement. However, in some jurisdictions such an arrangement is not possible because it would contravene the legal framework that governs the sector by impairing the independence of the regulator in a manner that is not consistent with that framework. In these systems, the tariff guidelines or tariff methodology should be articulated in a decision issued by the regulator or in a license granted by the regulator. The government support agreement should include a change in law clause in which the host country agrees that if (i) the regulator modifies the tariff guidelines, fails to apply the tariff guidelines, or issues decisions that are contrary to the tariff guidelines, and (ii) the actions (or inaction) of the regulator decrease the revenues earned by the concessionaire or increases the costs incurred by the concessionaire without affording the concessionaire a reasonable opportunity to recover those increased costs, then the host government will compensate the concessionaire. That compensation may take the form of a one-time payment or an ongoing subsidy to the concessionaire, depending on the nature of the action taken by the regulator.

The requirement to file a business plan with the regulator is particularly helpful in the context of a transmission concession. The rationale for implementing a transmission concession may include using private capital to finance significant improvements to, or significant expansions of, a transmission system. Many African countries have very low grid access and limited fiscal headroom to use public finances to expand their networks. A whole of network concession over all or part of a country could be a good way of using private capital to unlock service provision and increase energy access. Having the concessionaire submit a business plan to the regulator is useful because it facilitates a discussion around system planning, which impacts the capital expenses that will be incorporated into the regulated asset base during the next control period. ■



Concessions Part 3

Several issues are critical to the bankability of concession transactions. Those issues include how buy-out payments are calculated, some currency-related considerations, and the allocation of risks among the parties to the transaction and consumers. There are few examples of privately funded transmission concessions in emerging markets at present, so this article draws from the general principles applied to this model when it has been used elsewhere in the world. Specific concessions will normally have targeted approaches to address a specific local environment.

Buy-out payments

In a prior article in this series that describes how network utilities are regulated, we learned that:

- the component ($RateBase_y$ x $WACC_y$) provides a utility with a return on its investment;
- the depreciation component of a utility's annual revenue requirement provides investors with the return of its investment;
- shorter depreciation periods increase rates over the short term by increasing the depreciation component of a utility's annual revenue requirement but increase the overall returns paid by consumers because assets remain in the rate base for a longer period of time; and
- that many of the assets of a transmission utility have very long service lives and correspondingly long depreciation periods.

To use a simple example, let's examine the following fact pattern. A state-owned utility (the "grantor") enters into a concession with a 20-year term. The concessionaire places a transformer with an acquisition cost of $1 million into service on the first day of the concession. The regulator requires the concessionaire to use straight-line depreciation and establishes a depreciation period of 30 years for the type of transformer placed into service by the concessionaire. At the end of the 20-year concession, how much of the initial $1 million acquisition cost has been recovered by the concessionaire?

To determine the answer, we first convert a depreciation period of 30 years into annual depreciation of 3.33% of the acquisition cost. By multiplying $1 million times 3.33%, we can determine that the concessionaire will recognize $33,333.33 in depreciation each year and include that amount in the depreciation component of the annual revenue requirement. Multiplying this number by 20 years gives us the answer, which is that the concessionaire will have recovered $666,666.67 of its $1 million investment over the 20-year term of the concession.

In this example, the concessionaire will not have recovered $333,333.33 of its investment by the end of the concession. The concessionaire will recover this remaining amount, which is the undepreciated value of the transformer, by receiving a payment from the grantor at the end of the term of the concession. This type of payment is referred to as a hand-back payment, a buy-out payment, or a buy-out price. We will refer to it as a buy-out payment.

The above example shows how depreciation is recognized in relation to one particular asset. Building on this example, one might conclude that the best way to calculate a buy-out price is by summing the undepreciated value of each asset that was placed into service by the concessionaire. There is, however, a much simpler method of arriving at the same answer. The regulated asset base (in a performance-based regulation system, or the rate base in a cost-of-service system) is itself the sum of all investments made, less the sum of all depreciation recognized. As a result, the buy-out price at the end of the term of a concession can simply be set to equal the regulated asset base as of the end of the last year of the concession.

A significant advantage of this approach is that it allows the regulatory accounting system established by the regulator to be used to establish both the rates and the buy-out payment. This alignment results in consistency between decisions by the regulator regarding the regulatory asset base and the amount of the buy-out payment.

In scenarios other than the expiration of the term, the buy-out payment could be calculated by applying a multiplier to the regulated asset base. In the case of a termination of the concession following an event of default by the concessionaire, the multiplier would be less than 1.0. It may be 0.8 or 0.85 or 0.9, for example. In the case of a termination of the concession following (i) an event of default by the grantor under the concession agreement, (ii) an event of default by the host country under the government support agreement, or (iii) the occurrence of a prolonged political force majeure event, the multiplier would be greater than 1.0. In this case, it may be 1.1, 1.15, or 1.2, for example. These multipliers can be tailored to suit the objectives of the host country, the concessionaire, and the lenders to the concessionaire. The multipliers should provide a reasonable incentive for all parties to perform their obligations under the project agreements. They should not be viewed as, or sized in terms of, a penalty, which could be enforceable under the laws of many host countries.

Buy-out payments can be sizable. The amount of the buy-out price is directly correlated with the amount of investments made by the concessionaire during the term of the concession. One of the objectives of a concession is to incentivize the private sector to make the investments that are required to upgrade and expand a transmission system. As a result, if the concession is appropriately structured and successfully achieves that objective, then the investments made by the private sector will be sizable. So will the resulting buy-out payment.

A host government may find that a concessionaire has performed well over the term of the concession and that there is little rationale for allowing a concession to expire. A concession agreement and government support agreement may contemplate that the host country, the grantor, and the concessionaire may agree to extend the term of the concession before its expiration. If the term is extended, then the need to pay a buy-out payment will be delayed. Further extensions may indefinitely delay the need to pay a buy-out payment.

If a host country is not satisfied with the performance of a concessionaire, it may raise funds to pay the buy-out payment by awarding a new concession that requires the payment of an up-front concession fee that matches the amount of the buy-out payment. In the alternative, a host government in this position could re-capitalize the grantor by injecting equity into the grantor and causing the grantor to raise an appropriately sized amount of debt to fund the remaining portion of the buy-out payment. A grantor could raise that debt by issuing multiple series of bonds with tenors that correspond to the depreciation profile of the assets that constitute the regulated asset base, by borrowing from a syndicate of banks, or using a combination of these approaches.

Currency considerations

With the limited exception of countries that use a foreign currency to conduct financial transactions within their own economy and other very limited circumstances, the rates that are paid by electricity consumers are denominated in the currency of the host country. In many emerging market countries, capital markets and the market for loans from local banks are not sufficiently liquid to fund the debt component of the regulatory asset base of a transmission utility. Where this is the case, rates will need to be adjusted for changes in foreign exchange rates regularly.

Often these adjustments are applied quarterly and may be implemented by the concessionaire based on a formula contained in the tariff guidelines without the need for the regulator to issue a decision each quarter confirming the calculations made by the concessionaire. The formula should be designed to escalate only those components of the annual revenue requirement that are denominated in a foreign currency. Those components may include the return on the regulated asset base and depreciation, in which case the regulated asset base may also be denominated in a foreign currency. The foreign currency in which those items are denominated would be the foreign currency in which the concessionaire's loan obligations and equity contributions are denominated.

The operations and maintenance component and other components of the annual revenue requirement would be partially denominated in the same foreign currency and partially denominated in the currency of the host country. The percentage of those components that are denominated in the foreign currency would correspond to the percentage of the costs incurred that are denominated in the foreign currency. A large part of the operations and maintenance costs incurred by a transmission utility is for labor. As a result, a large part of the operations and maintenance component of the annual revenue requirement would usually also be denominated in the local currency.

Risks

An appropriate allocation of risks is essential to attracting investment in the form of both debt and equity. The risk matrix that follows describes how a range of risks might be allocated in a typical concession transaction.

Risk	Who Bears the Risk?	Comments
Financial		
Demand risk	Consumers	Demand risk is effectively allocated to consumers by the tariff guidelines. The tariff guidelines usually provide that if the concessionaire does not earn revenues equal to the annual revenue requirement during a particular year due to errors in forecasting the demand for transmission service, then the portion of the annual revenue requirement not earned as a result of the forecasting error is added to the annual revenue requirement for the following year, with interest.
Credit risk	Concessionaire, consumers	The risk that purchasers of transmission service may not pay for transmission service promptly is borne by the concessionaire but may be mitigated by (i) the use in the tariff guidelines of a target collection ratio that is less than 100% (typically only suitable in a model with a high number of off-takers), and (ii) a sovereign guarantee of payment by state-owned enterprises that purchase transmission service, or another form of liquidity support and/or support for termination payments in the event of non-payment.
Inflation	Consumers	The O&M component of the annual revenue requirement is adjusted for inflation. In general, the regulated asset base is not adjusted for inflation.
Interest rates	Consumers	Rates are typically adjusted for changes in interest rates regularly. The frequency of the adjustment may depend on how the concessionaire raised, or could reasonably be expected to have raised, debt financing. This can be a difficult risk to apportion in a market with variable liquidity such as those found in many African countries. The least cost approach to funding transmission services will usually be to adjust for changes in actual interest rates regularly.
Foreign exchange rates	Consumers	Rates are typically adjusted for changes in foreign exchange rates regularly. These adjustments are usually made each quarter.

Risk	Who Bears the Risk?	Comments
Land		
Pre-existing environmental conditions	Consumers	The cost of remedying pre-existing environmental defects that are material in nature constitute a capital cost that increases the regulated asset base.
Pre-existing defects in title	Consumers	The cost of remedying pre-existing title defects on behalf of the grantor constitutes a capital cost that increases the regulated asset base.
Land acquisition for expansions	Consumers	The cost of land acquired for new projects is included in the regulated asset base, usually when the asset is placed into service.
Technical		
Construction and commissioning of new assets	Concessionaire	The concessionaire is responsible for constructing and commissioning new assets.
Operations and maintenance, technical performance	Concessionaire	If the concessionaire incurs O&M costs that exceed the O&M component of the annual revenue requirement approved by the regulator, then the concessionaire will not achieve the cost of equity established by the regulator. The risk of underperforming against KPIs (see below) will need to be balanced carefully against O&M cost overruns when a concession is designed.
Key performance indicators, service levels	Concessionaire	If the concessionaire does not achieve the key performance indicators and/or the required service levels, it will incur penalties, which may be used to reduce rates. For transmission concessions, typical key performance indicators include measure of the frequency and duration of outages and measures of technical and commercial losses.
Licenses & Permits		
Initial issuance of licenses and permits	Government, grantor, and concessionaire	The concessionaire must apply for and diligently prosecute its applications for all licenses and permits. Significant licenses are granted at the commencement of the concession and usually have a term that is the same as the concession. If a public authority fails to grant a license or permit when the applicable requirements have been met, that failure will be treated as a political force majeure event.
Renewals, modifications	Government, grantor	A failure to renew a license or a modification to the terms of a license that effectively prevents the concessionaire from performing its obligations or exercising its rights under the concession will constitute a change in law.

Risk	Who Bears the Risk?	Comments
Social & Environmental		
Social and environmental impacts	Concessionaire	The concessionaire is responsible for conducting social and environmental impact assessments, complying with the stakeholder consultation and environmental laws of the host country, and, if the concessionaire's lenders are party to the Equator Principles, for complying with relevant performance standards issued by the International Finance Corporation.
Occupational health and safety	Concessionaire	The concessionaire is responsible for complying with the occupational health and safety laws of the host country, and, if the concessionaire's lenders are party to the Equator Principles, for complying with relevant performance standards issued by the International Finance Corporation.
Extraordinary Events		
Changes in law	Consumers, government	Changes in law that increase the costs incurred by the concessionaire or decrease the revenues earned by the concessionaire should be addressed through changes to the annual revenue requirement. To the extent they are not, they should be addressed through a change in law clause in the government support agreement.
Changes in tax	Consumers, government	Changes in tax that increase (or decrease) the tax obligations of the concessionaire should be addressed through changes to the annual revenue requirement. To the extent they are not, through a change in law clause in the government support agreement.
Force majeure events	Concessionaire, consumers	The concessionaire must mitigate the effects of force majeure events to the extent possible. Where it is practical to do so, the concessionaire may insure against these risks. The cost of the insurance is included in the operations and maintenance component of the annual revenue requirement. Capital costs associated with the replacement or repair of asset affected by a force majeure event are included in the regulated asset base to the extent they are not covered by insurance proceeds.
Political force majeure events	Consumers, government, grantor	If the concessionaire is prevented from performing its obligations or exercising its rights under the concession in a manner that is material due to the occurrence of a political force majeure event and the effects of such events continue for a prolonged period of time, an event of default may occur under the concession agreement.
Disputes		
Resolution of disputes under contracts	n/a	Disputes arising under the project agreements are resolved by international arbitration to the extent they are not resolved informally.
Resolution of disputes arising in relation to the tariff methodology	n/a	Disputes arising in relation to the application of the tariff methodology may result in claims under the change in law clauses of the government support agreement. Disputes regarding the proper application of such a change in law clause are then resolved by international arbitration to the extent they are not resolved informally.

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